18 March 2013

Ruspetro plc ("Ruspetro" or the "Company")

Preliminary Unaudited Results for the year ended 31 December 2012

Proved reserves up 35% to 234 million boe

Major Gas Agreement of Intent Signed

London, 18 March 2013: Ruspetro plc (LSE: RPO), the independent oil & gas development and production company listed on the London Stock Exchange, with operations in the Khanty-Mansiysk region of the West Siberian basin, announces today its results for the full year ended 31 December 2012 and an update on its operations to date.

Key Highlights

- 97% increase in revenues year on year at US$76.23 million (net of export duty)
- Full year EBITDA of –negative US$6.2 million, EBITDA for Q4 2012 positive at US$2.4 million
- Proved reserves up 35% to 234 million boe (31 December 2012). Including 32 million boe increase in oil and condensate reserves and 29 million boe of commercial gas reserves
- Proved and probable gas reserves of 153 million boe
- Average 2012 production up 81% over 2011 at 4,639 boepd
- Net debt of US$335.9 million at year end, with US$34.4 million of cash

Post-period update

- Current production at 6,374 boepd, of which 1,335 boepd is condensate
    - February average production was 5,930 boepd, of which 1,417 boepd was condensate
    - Current gas production of 9,400 boepd excluded and not currently available for sale
- In order to monetize its newly discovered gas reserves, the Company has signed an "Agreement of Intent" to supply OJSC Fortum with dry gas for eight years with a sales value of up to US$700 million from the second half of 2014. OJSC Fortum, a subsidiary of a leading Finland based electricity generator, is an electricity utility with a 1,200 MW power plant in Nyagan (which is 100km north of Ruspetro's field). The Company is designing a gas processing plant with a sales pipeline and is in discussions with third parties as to the required project financing for this plant.

- As at 28 February 2013, the Group had US$20 million of cash and will require additional financing to further field development and to achieve significant and sustained production increases. As at the date of this statement, the Company is in discussions with existing lenders as to additional financing and the extension of debt maturity beyond May 2015.

Outlook

- In light of the commercial gas agreement, Ruspetro is currently undertaking a review of its development plan
- Crude oil and condensate drilling to continue using fit for purpose completion technologies
- Waterflood operations to be expanded
- Gas business to be developed

	2012	2011	Change
Revenue (US$m)	76.23	38.72	+97%
Well head revenue per barrel (US$/boe)	24.50	19.83	+24%
Oil and condensate production, total (boe)	1,697,950	935,003	+82%
Average production (boe)	4,639	2,560	+81%
Proved reserves (mmboe)	234	173	+35%
Probable reserves (mmboe)	1,604	1,372	+17%

Don Wolcott, chief executive, commented:

"Over the course of the year we have faced some significant challenges. We are clearly disappointed not to have met our production targets to date but we have implemented a number of initiatives which have had a beneficial impact on the business and led to a positive EBITDA in the final quarter. While the development of our field is at an early stage, we have successfully increased our proved reserves base and are developing a significant gas business validated by the recent signature of an Agreement of Intent to supply dry gas with an expected sales value of USD $700million over the period of the Agreement. We are currently developing a plan to build production and we are working with our lender to arrange the required financing."

For analysts and investors

The Company will host a meeting for analysts on 12 April 2013.

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About Ruspetro

Ruspetro plc is an independent oil & gas development and production company, listed on the premium segment of the London Stock Exchange (LSE: RPO). The Company's operations are located on three contiguous licence blocks in the middle of the Krasnoleninsk Arch in Western Siberia. Ruspetro assets include proved and probable (2P) reserves of over 1.8 billion barrels of oil equivalent.

CHAIRMAN'S STATEMENT

2012 was a profoundly challenging year for Ruspetro. The outturn, in terms of production, and consequently returns for our shareholders, was disappointing. But to assess the Company's performance fully, one must also look deeper into all levels of the company's operations. Here, I have been encouraged by a number of positive developments and above all by the tenacity of my executive colleagues in getting to grips with the challenges in the business.

While in private ownership, Ruspetro had existed on the lightest footprint possible to conserve resources before the commencement of substantial cash flows. As a result, post IPO, the senior executive team has had not only to carry forward the field development programme but also to build the company. I am particularly impressed by the speed and thoroughness with which Don, Tom, Alexander and their colleagues have completed this exercise. We have recruited a strong international team with experience from a variety of operating environments around the world. At a time of human resource shortage in our industry, I am encouraged by the calibre of recruits, and take this as an endorsement of the quality and potential of our business. We now have all the necessary human, technical and engineering resource in our three centres: the London plc office, the Moscow operational centre and the Siberian field offices to handle the anticipated growth in the business.

Turning to our assets, despite the challenges of production, we take considerable encouragement from the further increases to our proved and probable hydrocarbon reserves, the second since flotation announced post year end. At these levels, the scale and quality of our reserves provide a basis of full confidence for our medium and long-term production plans. However, in the short term, we have to recognise that technical issues of recovery have frustrated our ambition in 2012. Varying permeability and lower than expected flow rates in the first half and much higher associated gas production in the second, both presented technical challenges for the management team. Here too, I have been impressed by the adaptability and energy that the senior executive team have shown. For example, the emergence of a gas and condensate play in the north east of our field, while creating a technical challenge, has markedly benefited cash flows.

The construction of pipelines, the structuring and signing of contractual supply relationships for fracturing, the completion of processing facilities, and finally the development of the condensate processing plant in the depths of the Siberian winter are all real proof of the team's resourcefulness and drive. It is on this basis that I am confident we are equal to the tasks ahead, and that stakeholders can expect the picture to improve.

Securing further financing is essential for the continued development of the field. In this regard, we are discussing our financial requirements with our major lender and we aim to secure this financing in the near future.

In what has been a challenging year for the business I should like to thank all our employees who have worked with great dedication to carry us through this period. My thanks should also go to my fellow board members who have been engaged in the business, giving vital, sometimes critical, but always supportive advice. Our commitment to the best governance remains absolute and we continue with our comprehensive monitoring and vigorous pursuit of any possible improvements to the Company's Health, Safety and Environmental performance.

Chris Clark, Chairman Ruspetro

CHIEF EXECUTIVE'S REVIEW

The Ruspetro team made some significant accomplishments during 2012. Unfortunately, we did not meet our principal objective which was to reach a 10,400 boepd production target. I am sincerely disappointed with that result. Nonetheless, we did achieve a great deal. We created a business that efficiently develops, produces and sells hydrocarbons.

Following our Initial Public Offering ('IPO') on 19 January 2012 we needed to move quickly and accomplish six key objectives, which were to:

1) Build a team

2) Develop, sales, treatment and access infrastructure urgently

3) Grow production

4) Improve reserve quality by increasing the proved category (1P)

5) Develop a strategy to develop and monetize our gas resources

6) Improve the Company's finances; in order to develop the Company towards being cash flow positive

The immediate challenge was to increase the pace of development of the Company. To do this we needed to get more rigs into operation, start and complete on schedule the construction of a sales pipeline to link the Company's processing facility with the Transneft pipeline network, build a pump station and increase oil treatment capacity. At the time of the IPO, we had only one rig in operation on Pad 21, with no more room for expansion to drill further wells. For other rigs to be activated, we needed to extend existing pads and build the roads, power lines and pipelines to connect them. Within days of the IPO, we began procurement of the pipe for the 27km sales pipeline and in parallel began trenching operations. Concurrently, we started extending Pad 21 in preparation for more drilling. This level of activity, while impressive, did require a more capable team to manage the multiple parallel processes for this pace of field development.

During the year, we increased the size of our team considerably in order to be able to gain the expertise and management capability necessary to triple our drilling program, build-out the required infrastructure, increase our production and improve our understanding of the field. The new team needed to be able to deliver on our fast paced rollout. We were able to bring key people into the Company with both international and local business backgrounds. They have roles and responsibilities throughout the business, in operations, in our subsurface department and in the finance, legal, human resources and HSE departments both in the head office in Moscow and in our UK plc office in London.

This team executed our field development program successfully by mobilizing four additional rigs in the field over the course of the year and drilling 33 wells whilst improving the surface infrastructure to provide access, electricity and pipelines to all working pads. This also included building and commissioning the 27km sales pipeline ahead of schedule and significantly under budget. The Company now has 15,000 bopd of processing capacity for our crude oil production in our West field area, and 9,000 bopd of processing capacity for condensate and 3 million cubic meters of gas processing capacity per day in the north of the field. The team continues to exceed the regional benchmarks in the construction of pipelines, power lines, roads and facilities.

While the Company made great strides in putting in significant infrastructure quickly and at a lower cost than budgeted, growing production at the tempo we had initially planned proved to be difficult. Our plan at IPO was to continue development of the structural high in the west of the field. Our mapping showed the geology progressing on-trend to the east and west from Pad 21. As we had some existing infrastructure to the east of Pad 21 and knowledge of the formations from 3D seismic, we directed our development efforts in this direction by building Pad 19, erecting a rig and beginning to drill. After drilling several wells in different areas from Pad 19, we were met by consistently lower permeability than we had found previously. The reservoir rock had similar thickness and in some cases superior porosity to the reservoir accessible from Pad 21 but, due to the lower permeability, the wells were only yielding approximately 150 bopd of initial rate after fracture treatment. At the same time that we were experiencing poor reservoir quality from Pad 19, we were getting better results from the gas-condensate reservoir in the north of the field.

The gas-condensate field provided two positives. Firstly, the well rates and reservoir quality, while variable, were on average better than our findings from Pad 19. Secondly, the Mineral Extraction Tax ('MET') for condensate is approximately US$20 less per barrel than for crude oil. This lower fiscal burden nearly doubled the Well Head Revenue ('WHR') of production on a per barrel basis.

The combination of the higher flow rates and the much lower rate of MET currently makes condensate far more cash generative to produce and sell than crude oil. In the second half of the year, we capitalized on this and refocused our drilling strategy towards this condensate rich area. To do this, it was necessary to mobilize rigs and build an early processing facility ('EPF') to stabilize the condensate before it could be taken to its destination refinery by truck and rail. With the increase in gas and condensate production during the year, several upgrades to the production system were conducted including upgrading the infield pipelines, separation, water disposal and testing equipment.

At the end of 2012, it was necessary to further upgrade the EPF to manage the large volumes of gas production and to dissipate the heat carried to the surface by the gas and condensate production. A heat exchange system, new separators and larger diameter flow lines were all added to the facility to bring the temperature and pressure of the well production to a point whereby the condensate could be stabilized. However, when the heat exchange system was commissioned reservoir pressure decline and the resultant drop in condensate yield meant that condensate production did not rise as initially expected.

The increased gas supply and reserves identified by the development work in the north of the field has been instrumental in pushing forward our gas utilization and monetization strategy. This strategy is discussed in more detail below.

From the Company's inception it has been our stated aim to increase the quality of our reserves. 2012 saw a 35% increase in our proved reserves, which now stand at 234 mmboe. This is a 61mmboe increase of which 29mmboe are the proved gas reserves added due to the development of the gas and condensate play in the north of the field.

The respectable current gas production in the north of the field associated with the condensate we are selling presents the potential for a significant gas business for Ruspetro that will enhance our profitability when brought on-line. This was not something that we envisaged to be feasible a year ago. We are currently producing about 1.6 million cubic meters per day (9,400boepd).

We have been developing a gas monetization plan to allow us to sell our associated petroleum gas to several potential clients. The initial primary customer is a commercial electricity generating plant being constructed in the region. Other potential customers are available via the Gazprom pipeline network, which is beginning to open up in response to the Russian Government's drive towards greater utilization of associated gas by oil producers.

The planning process for a gas processing plant and pipeline is underway and we intend to start the build during the winter of 2013 with revenues from the project beginning to be realized in the second half of 2014. The gas business will have relatively low operating costs and thus will become another high margin revenue stream for Ruspetro.

Outlook

Our main priority for 2013 is to deliver on our growing cash generation. We will continue to develop the gas-condensate play in the north of the field. This will help to build our revenues and cash flows, which will give us the flexibility to grow our business significantly in the coming years.

Building production and making sure that we execute our drilling program are the main tasks ahead of us now. We will look to expand our gas business to sell substantially all of the associated gas produced to third parties from the second half of 2014.

In our crude oil area, we will continue to expand waterflood operations as we are now seeing stabilization, and in some cases increases, in reservoir pressures. This is beginning to generate production enhancement opportunities and will continue to do so in 2013. We will also look to resume drilling and increase the range of completion technologies used to optimize production from the varying geology of the field in 2013.

With these aims in mind we are currently working with our lender to arrange the required financing.

Conclusion

Over the course of 2012, we increased our proved reserves base as well as the pace of well completions. We have completed the surface infrastructure necessary to build production and have engaged the necessary contractors to ensure an optimal well completion tempo. We identified significant contributions from higher-value condensate which has, in turn, driven a change in direction for our short term initiatives.

We have gained valuable insights into the characteristics of our field in 2012, marking it out as a year of delineation for Ruspetro. Although there have been some disappointments, we have the measures in place to capitalize on the vast potential of our field. The years ahead will draw on these insights to allow us to effectively exploit the intrinsic value of Ruspetro’s assets.

Don Wolcott, CEO Ruspetro

OPERATIONAL REVIEW

Our reserves are audited twice yearly by DeGolyer and MacNaughton. The 31 December 2012 audit includes, for the first time, the characterisation of the gas and condensate producing formation in the Palyanovo license block in the north east of the field.

Proved reserves have increased by 35% since our 31 December 2011 audit to 234 million barrels of oil equivalent ("mmboe"), of which 205 mmboe are liquids.

The Company currently has proved-developed reserves of approximately 16.1 million barrels of oil and condensate, this compares to 11.6 million barrels as at 31 December 2011, a gain of 40%. We will endeavor to grow these reserves over the coming years as our drilling programme expands. Proved and probable ('2P') reserves have increased by 19% to 1.84 billion barrels of oil equivalent ('boe') since our 31 December 2011 audit as a result of increased Original Oil in Place identified during on-going geological work and the discovery and characterization of our gas and gas condensate field in Palyanovo. The total increase in proven reserves was 61mmboe.

For the first time we now have significant proved and probable gas reserves in our field. We are currently treating and selling some of our condensate, and are developing treatment and delivery systems to monetize the remainder of the gas and gas liquids.

We will continue to migrate probable reserves to proven and proved reserves to proved-developed as we expand our drilling programme, deliver waterflood results and refine our geological and hydrodynamic models. Increases will be come from increased recovery factors driven primarily by water-flood operations and changes in our OOIP and geological model as we refine and reprocess our seismic and well test data.

We are continually developing our understanding of the field, by reprocessing the 3D seismic and historical log data that we acquired with the field and by increasing our data set with each additional well drilled. We believe that there remains substantial additional opportunity in our field in both conventional and unconventional reserves, and we will continue to develop and refine our models through processing new well data and the acquisition and interpretation of new seismic data in the future.

Our next reserve audit will be dated 30 June 2013.

Sales and marketing

In 2012, the Company produced a total of 1,697,950 bbls of oil of which 1,650,294 was sold. An increase in production of 82% from 2011 production of 935,003 bbls.

21% was crude oil sold for export via the Transneft pipeline system (350,791 bbls). For export sales we work with an international oil trading company who sells our crude to a refinery in Hungary. Currently we have a quota to export up to 35% of our production.

We have recently delivered our first crude oil cargo by tanker to Rotterdam in the Netherlands, demonstrating our flexible approach to oil sales and commitment to maximizing our product prices. We remain opportunistic in our approach to sales and price maximization of our high quality crude and condensate. To achieve our net-back goals we have increased our evacuation routes and delivery options considerably since IPO. In addition to pipeline sales to local refineries, we are now able to sell crude oil and condensate in Russia and internationally by truck, rail, barge and tanker. Flexibility in our delivery destinations and a broader customer base is the key to maximizing pricing and we will continue to opportunistically explore and develop new ways to realize our hydrocarbons in 2013.

In 2012, we completed our 27km sales pipeline connecting our treatment facility to the Transneft system and built an entirely new facility to treat gas and gas-condensate in our new gas field. We also began preliminary route design for gas and condensate pipelines and the initial engineering for a gas processing plant in our Palyanovo field. We will continue to improve on the existing treatment systems and continue developing our gas processing and pipeline infrastructure during 2013.

Condensate made up 15% of our sales volume in 2012 and 27% of our well head revenue. This product was sold directly to a domestic off-taker from the Early Processing Facility (EPF). The off-taker arranges road and rail transport from the EPF and gives Ruspetro a price net of these costs.

In 2012 Ruspetro also earned US$ 1.4m by providing access to the Transneft pipeline via our metering station to third party oil producers in the region.

Drilling

The Company drilled 33 wells in 2012 at a cost of US$66 million including fracturing and connections to our gathering system. During the year, we mobilised four rigs, two in the west of the field drilling into the UK2-3 formation to produce crude oil and two in the north east of the field drilling into the UK8-10 formations where we had identified a gas condensate play.

Our drilling program in the west of the field revealed two issues that we are currently addressing. First, that the reservoir pressure in the Pad 21 area has been lowered by historic production in this area and hydraulic communication between bottom-hole locations. Second, drilling to the east of pad 21 revealed similar formation structure, thicker oil-bearing intervals and equivalent or better porosity, but upon completion the permeability of the sands and thus the flow-rate was shown to be significantly lower than that previously known on pad 21.

To address the lower reservoir pressure we have initiated a water injection programme in this area, beginning to convert producer wells to water injection wells in the middle of 2012. We have begun to see pressure response in neighboring wells as a result of the waterflooding.

In order for the Company to predictively select higher quality bottom-hole locations across the field, we will need to improve the resolution of our seismic maps and the geophysical clarity of our geological model. To achieve higher resolutions, we have completed some reprocessing and inversion analysis of the existing 2D & 3D seismic that covers 100% and 42% of the field respectively.

The Company had an average 39 day spud to completion time, of which 21 days was required to drill and case a well. We added drilling contractors to the field in 2012, most significantly with a Weatherford and a SSK rig. Both rigs are capable of best-in-class vertical well drilling times and quality. Both rigs are also capable of drilling horizontal sections.

Water injection

The Company started its water injection programme in June with the conversion of 2 wells to water injectors. Water-flood increases recoveries through reservoir pressure maintenance and by mobilizing oil towards producing well bores ('Sweep'), and is an integral part of our field development plan.

We are beginning to see physical response to this activity, as modelled, which will enable us to slow or temporarily halt production declines attributed to pressure drop, and possibly create enhancement candidates in some of our well stock. We will also be submitting this empirical data to our reserves auditors and moving some parts of our field further towards water-flood recovery factors.

As part of this programme, we have installed a water pumping station at the central processing facility that enables the Company to recirculate separated water back to the pads for reinjection into the formations.

Fracturing

Ruspetro designs and implements fracture treatments as a standard completion practice on all new wells. Fractures are designed individually for the zone of interest in a given well, and we employ world-class fracturing service contractors to implement our designs. Mathematically, a fracture is simply a much larger well bore, and provides a large increase in effective permeability and thus the ability of a given well to produce. At the beginning of the year, our international oil service contractors provided fracturing services in the field with consistency. However, increasing demand in the neighboring fields during the year resulted in inconsistent fracture scheduling and delays in the completion of several wells.

We therefore initiated and established a successful relationship with Weatherford International Ltd who, in the second half of the year, became our primary fracturing service contractor in the field. The relationship was advantageous to Weatherford as it allowed them to establish themselves in the region with a depot in our field and a significant number of Ruspetro wells to be fractured. For the Company, it enabled us to bring our completion back log up to date, allow new wells to be completed on schedule and gave us a consistent, high quality partner in the field to meet our requirements going forward.

Infrastructure investment and delivery

2012 was a year in which we completed several key infrastructure projects at a speed and cost we believe to be highly competitive in our environment. Transportation, treatment and gathering infrastructure that we built in 2012 will provide processing and evacuation capacity to support production growth for the next several years.

Immediately after our IPO we began work on and completed the 27km sales pipeline that transports crude from our central processing facility to our wholly owned metering station on the Transneft pipeline from where we can sell our crude to Russian and European customers. We completed this project on time and under budget, and eliminated US$2.28/bbl of trucking costs from our field to our existing Transneft connection point.

The Company completed several projects during the year to secure and strengthen its power supply within the field. We installed a 300 amp step-up transformer at the Talinka substation which provides the main power source for the western part of the field. The Company constructed the necessary in-field power lines to increase drilling and production. We also purchased 4MW of electricity generators to enable us to utilise some of our associated petroleum gas in electricity production. A petroleum gas generator can reduce the daily cost of power of running a rig to US$800 from US$1,500 when compared to using power from the grid. This brings the cost of power to drill a new well down to US$16,800 from US$31,500.

The necessary In-field pipeline network has been completed to bring production fluid from the wells to the processing facilities and transport processed water back to the pads via the newly installed water pumping station at the central processing facility.

The in-field electricity grid, the in-field pipeline system for production fluids, processed water for reinjection and the system partially powered by associated gas brings us closer to our goal of having a closed loop production system producing, treating and transporting crude directly from our fields to end-customers world-wide.

Condensate production

We started selling gas condensate to domestic customers in April 2012 with the completion of well 1004 in the Palyanovo License Block. Condensate refers to 51 degree API light oil being produced in the north of the field.

Condensate production has two main advantages for our business. First, condensate is a premium product in high demand throughout Russia and commands a price premium to crude oil. Second, condensate has been subject to a Mineral Extraction Tax (MET) of RUR556 per ton in 2012, RUR591 per ton in 2013 and RUR647 per ton in 2014. RUR591 per ton is, currently, the equivalent of approximately US$2.30 per barrel, as compared to our average MET for crude oil in 2012 of US$22 per barrel. Consequently, the well head revenue of condensate production is approximately US$20 per barrel greater than the well head revenue for crude oil production.

This overwhelming net revenue advantage has incentivized the Company to reorient our drilling program towards the condensate producing area of the field in the near term.

Condensate now comprises approximately 25% of our production.

Associated Gas Production – A Potential New Revenue Stream

With significant gas reserves and production and accessible sales point available, associated gas production at Ruspetro may contribute significantly to our revenues in coming years.

Associated gas production is currently 1.6 million cubic meters per day (9,400boepd) due, in large part, to significant gas production in the Palyanovo condensate field. This production is now being flared and as such is lost revenue for the Company.

As stated in the 31 December 2012 DeGolyer and MacNaughton reserves' audit, the Company has proved and probable gas reserves of 153 million boe.

The Company has recently signed an "Agreement of Intent" to supply OJSC Fortum, an internationally owned local electricity utility, with dry gas for eight years. This is projected to generate revenues for the Company of up to US$700 million during this period

The Company has already made substantial progress designing the gas processing plant and pipeline required to commercialize the gas and is seeking to arrange the required financing for this project. These elements may be completed by the middle of 2014, putting Ruspetro in a position to market and sell dry gas locally or via the Gazprom pipeline network.

The processing plant will not only enable the Company to sell dry gas to the generating plant in Nyagan but will also increase the efficiency of our condensate production, thereby increasing yields substantially. Additional products resulting from the processing of gas will include large quantities of propane and butane which can be sold commercially from the plant as liquids.

Gas flaring

The penalties for gas flaring paid in 2012 totalled US$850,000 under the law in force during the period. The regulations for gas flaring and emission limits, however, have been revised and as a consequence we will not suffer penalties for associated gas flaring in 2013.

According to the Russian Federation Government legislation, effective 1 January 2013, companies involved in the production of associated gas are required to reduce the amount of flaring of associated gas to 5% or less of the overall amount of associated gas produced, with the exception of early stage production companies.

Ruspetro, as an early stage production company as defined under the law, can flare up to 100% of its associated petroleum gas for 3 years or until our proved and probable reserves are depleted by 5%. Depletion, as at 31 December 2012, is less than 1% of the proved and probable reserves of the field.

The gas utilization and commercialization plan as described above for the gas produced in this area will reduce flaring, therefore eliminating future penalties, and optimize the economic potential to the Company of the produced gas.

FINANCIAL REVIEW

For 2012, we ended the year with revenues of US$76,230 thousand. This was an increase of 97% from 2011, and was achieved by increasing average production for the year to 4,639 boepd from 2,560 boepd. Full year production was 1,370,960 boepd of crude oil and 326,990 boepd of condensate and we achieved an exit rate of 6,540 boepd at the end of the year. Revenues are reported net of export duty.

We also generated positive EBITDA of US$2,426 thousand in the fourth quarter of 2012 thanks, in large part, to our focus on condensate production. EBITDA over the year was negative -US$6,223 thousand with our absolute production and sales volumes being lower than anticipated at the time of our IPO.

Cost of sales

2012 cost of sales (including depreciation) was US$74,816 thousand and represented 98% of revenues in 2012 as compared to 135% of revenues in 2011. The increase in the cost of sales was primarily as a result of increasing sales volumes and increasing the scale of the business in anticipation of further sales volume increases.

The higher sales related costs include Mineral Extraction Tax of US$31,816 thousand which was 68% higher than the prior year commensurate with an increase in production volumes of 82% year on year. Other sales costs increased by 29%, reflecting both increased production volumes and expenditures in anticipation of the future development of Ruspetro's business. Operating expenses excluding depreciation and MET was approximately $25,093 thousand compared to $9,719 thousand in 2011.

Compared with 2011 depletion, depreciation and amortization decreased by US$5,820 thousand, or 25%, to US$17,907 thousand, as a result of an increase in the proved developed reserve base, partly offset by an increase in production. Other costs of sales include sundry and costs of materials used in production.

Selling and Administrative Expenses ("S&A")

S&A expenses (excluding share based payments) increased to US$28,446 thousand, or 90% from 2011. S&A expenses include oil transportation costs, payroll expenses, rent, professional services, property and land taxes, bank charges and other expenses, including costs associated with Ruspetro's status as a public company. The increase in S&A reflects the management resources and expertise required for an increased scale of operational activity and production.

Comprehensive Loss for the Year

The Company recorded a loss for the year of US$27,284 thousand. This was approximately 68% lower than the 2011 loss of US$85,063 thousand. After translating the results to the presentation currency, which resulted in a gain of US$6,061 thousand, the total comprehensive loss for the year was US$21,223 thousand.

Cash Flow

Our IPO raised net cash proceeds of US$213,699 thousand with the issue of 126,128,848 new ordinary shares bringing the total number of ordinary shares in issue to 333,381,480 of ten pence each.

We started the year with $1,294 thousand in cash, after receiving US$213,699 thousand net cash from our IPO we repaid debt of US$18,575 thousand and paid interest during the year of US$50,645 thousand. We spent US$66,014 thousand on drilling (49% higher than our development plan at IPO) and US$40,569 million on infrastructure development (18% lower than budgeted in our development plan at IPO) during the year. After an operating cash outflow before working capital adjustments of US$7,511 thousand, working capital adjustments of negative $1,291 thousand and a currency translation difference of positive US$3,941 thousand we ended the year with a closing cash balance of US$34,416 thousand.

Purchase of property, plant and equipment ("PP&E")

The Company invested US$106,583 thousand in property, plant and equipment in 2012 representing an increase in investment over 2011 of 229%. PP&E assets were US$226,736 thousand at the end of the period, an increase of 104%, whilst mineral rights and other intangibles increased by 6% to US$425,551 thousand.

Financing of Ruspetro's Current Operations and Future Development

On the basis of its current financial resources and its existing external and shareholder debt finance, Ruspetro's development in 2013 and beyond will require additional funding.

While the existing US$286.7 million facility with Sberbank is due in April 2015, securing financing is essential for the continued development of the field. Therefore Ruspetro is currently evaluating a number of financing options including additional financing and term extension of its existing debt with our major lender. Such discussions are currently underway and it is hoped that this refinancing will be agreed in the near future.

If additional financing is not obtained, the Group may be unable to realize its assets and discharge its liabilities in the normal course of business. Management considers that these circumstances represent a material uncertainty that may cast doubt on the Group's and Company's ability to continue as a going concern.

Ruspetro Plc

Preliminary Unaudited Consolidated Financial Statements
As at and for the year ended 31 December 2012

Unaudited Consolidated Statement of Comprehensive Income for the year ended 31 December 2012
(presented in US$ thousands, except otherwise stated)

	Year ended 31 December	
	2012	**2011**
Revenue	76,230	38,718
Cost of sales	(74,816)	(52,355)
Gross Profit/(loss)	**1,414**	**(13,637)**
Selling and Administrative expenses	(40,481)	(14,982)
Other income / (expenses), net	20,215	(1,385)
Operating loss	**(18,852)**	**(30,004)**
Finance costs (net)	(29,815)	(33,126)
Change in fair value of call option	(3,240)	-
Foreign exchange gain / (loss), net	23,804	(25,535)
Loss before income tax	**(28,103)**	**(88,665)**
Income tax benefit	819	3,602
Loss for the period	**(27,284)**	**(85,063)**
Other comprehensive income		
Exchange difference on translation to presentation currency	6,061	7,291
Total comprehensive loss for the period	**(21,223)**	**(77,772)**
Loss attributable to:		
Equity holders of the parent	(27,284)	(81,095)
Non-controlling interests	-	(3,968)
Loss for the period	**(27,284)**	**(85,063)**
Total comprehensive loss attributable to:		
Equity holders of the parent	(21,223)	(74,169)
Non-controlling interests	-	(3,603)
Total comprehensive loss for the period	**(21,223)**	**(77,772)**
Loss per share		
Basic and diluted loss per ordinary share (US$)	(0.09)	(0.41)

Unaudited Consolidated Statement of Financial Position as at 31 December 2012
(presented in US$ thousands, except otherwise stated)

	31 December	
	2012	**2011**
Assets		
Non-current assets		
Property, plant and equipment	226,736	111,313
Mineral rights and other intangibles	425,551	401,513
	652,287	**512,826**
Current assets		
Inventories	2,567	2,610
Trade and other receivables	19,721	5,810
Income tax prepayment	37	36
Other current assets	24	-
Cash and cash equivalents	34,416	1,294
	56,765	**9,750**
Total assets	**709,052**	**522,576**
Shareholders' equity		
Share capital	51,226	7
Share premium	220,506	49,994
Retained loss	(85,400)	(60,208)
Exchange difference on translation to presentation currency	(24,061)	(30,122)
Other reserves	18,176	-
Equity, Retained earnings / (Accumulated loss) and other reserves attributable to Parent	**180,447**	**(40,329)**
Non-controlling interests	**-**	(408)
Total equity	**180,447**	**(40,737)**
Liabilities		
Non-current liabilities		
Borrowings	348,493	360,250
Provision for dismantlement	7,697	5,961
Deferred tax liabilities	89,900	85,726
Other non-current liabilities	15,365	-
	461,455	**451,937**
Current liabilities		
Borrowings	21,804	46,197
Trade and other payables	39,721	13,496
Taxes payable other than income tax	4,544	4,226

Other current liabilities	1,081	47,457
	67,150	**111,376**
Total liabilities	**528,605**	**563,313**
Total equity and liabilities	**709,052**	**522,576**

Unaudited Consolidated Statement of Changes in Equity for the year ended 31 December 2012
(presented in US$ thousands, except otherwise noted)

	Attributable to owners of the Parent							
	Share capital	Share premium	Retained earnings / (Retained loss)	Exchange difference on translation to presentation currency	Other reserves	**Total**	Non-controlling interests	**Total equity**
Balance as at 1 January 2011	**6**	**39,989**	**20,887**	**(37,049)**	**-**	**23,833**	**3,195**	**27,028**
Loss for the period	-	-	(81,095)	-	-	(81,095)	(3,968)	(85,063)
Other comprehensive income for the period	-	-	-	6,927	-	6,927	365	7,291
Total comprehensive income / (loss) for the period	**-**	**-**	**(81,095)**	**6,927**	**-**	**(74,168)**	**(3,603)**	**(77,772)**
Issue of share capital	1	10,005	-	-	-	10,006	-	10,006
Balance as at 31 December 2011	**7**	**49,994**	**(60,208)**	**(30,122)**	**-**	**(40,329)**	**(408)**	**(40,737)**
Balance as at 1 January 2012	**7**	**49,994**	**(60,208)**	**(30,122)**	**-**	**(40,329)**	**(408)**	**(40,737)**
Loss for the period	-	-	(27,284)	-	-	(27,284)	-	(27,284)
Other comprehensive income for the period	-	-	-	6,061	-	6,061	-	6,061
Total comprehensive income / (loss) for the period	**-**	**-**	**(27,284)**	**6,061**	**-**	**(21,223)**	**-**	**(21,223)**
Reorganization of the Group	31,818	(49,994)	(249)	-	18,176	(249)	408	159
Issue of share capital	19,401	220,506	-	-	-	239,907	-	239,907
Share options of shareholders	-	-	(9,694)	-		(9,694)	-	(9,694)
Share-based payment compensation	-	-	12,035	-		12,035	-	12,035
Balance as at 31 December 2012	**51,226**	**220,506**	**(85,400)**	**(24,061)**	**18,176**	**180,447**	**-**	**180,447**

Unaudited Consolidated Statement of Cash Flows for the year ended 31 December 2012
(presented in US$ thousands, except otherwise stated)

	Year ended 31 December	
	2012	**2011**
Cash flows from operating activities		
Loss before income tax	(28,103)	(88,665)
Adjustments for:		
Depreciation, depletion and amortization	19,762	24,524
Foreign exchange (income) / loss	(23,804)	25,535
Finance costs	29,815	33,126
Change in fair value of call option	3,240	-
Gain on Settlement of Makayla debt	(21,282)	-
Share-based payment compensation	12,035	-
Other operating expenses	826	2,286
Operating cash flow before working capital adjustments	**(7,511)**	**(3,194)**
Working capital adjustments:		
Change in trade and other receivables	(964)	(530)
Change in inventories	43	(472)
Change in trade and other payables	12,259	(648)
Change in other taxes receivable/payable	(12,629)	4,292
Net cash flows generated / (used in) operating activities	**(8,802)**	**(552)**
Cash flows from investing activities		
Purchase of property, plant and equipment	(106,583)	(32,335)
Net cash used in investing activities	**(106,583)**	**(32,335)**
Cash flows from financing activities		
Proceeds from issue of share capital	213,699	10,006
Repayments of loans and borrowings	(18,575)	-
Interest paid	(50,645)	-
Cash inflow on reorganization	87	-
Net cash generated from financing activities	**144,566**	**10,006**
Net increase / (decrease) in cash and cash equivalents	**29,181**	**(22,881)**
Effect of exchange rate changes on cash and cash equivalents	3,941	5,310
Cash and cash equivalents at the beginning of the period	1,294	18,865
Cash and cash equivalents at the end of the period	**34,416**	**1,294**

The accompanying notes on pages 9 to 38 are an integral part of these consolidated financial statements

1. Basis of preparation

The announcement has been prepared in accordance with the Company's accounting policies, which in turn are in accordance with International Financial Reporting Standards ('IFRS') as adopted by the European Union ('EU') and applied in accordance with provision of the Companies Act 2006.

The results are unaudited, however we do not expect there to be any difference between the numbers presented and those within the annual report.

The financial information set out here does not constitute the Group's statutory accounts, but is derived from those accounts. The statutory accounts for the year ended 31 December 2012 will be delivered to the Registrar of Companies following the group's annual general meeting. Accounts will be dispatched to shareholders as soon as practicable.

Going concern

These consolidated financial statements are prepared on a going concern basis, which presumes that the Group will be able to realize its assets and discharge its liabilities in the normal course of business in the foreseeable future.

At 31 December 2012, the Group had net current liabilities of $10,385 thousand, which included cash in hand of $34,416 thousand. Furthermore, the Group has a long-term loan from Sberbank amounting to $286,671 thousand, which is repayable in May 2015, together with long-term shareholder loans of $61,822 thousand which are also repayable in May 2015.

Management considers that the continued operational existence of the Group is dependent upon the ability to make further investment in field development in order to increase hydrocarbon production and sales. In response to these circumstances, management are in discussions with existing lenders with regard to the provision of additional long-term debt financing and the extension of the maturity of the existing long-term loans.

Management considers the additional financing and the maturity extension of existing debt will provide sufficient financial resources such that the Group can further invest in field development with the intention of raising production. Management further considers that the additional cash flows to be generated from production would allow the Group to service debt, increase production and fund other Group activities. In developing their cash flow forecasts, management have been required to make a number of significant assumptions. These include assumptions as to future hydrocarbon prices, taxes, production volumes, and inflation, are further discussed in Note 3.

Agreements with the existing lenders as to additional financing and maturity extension have not been entered into as of the date of these financial statements. In the event that such additional financing and maturity extension is not obtained, the Group may be unable to realize its assets and discharge its liabilities in the normal course of business.

However, on the basis of the assumptions and cash flow forecasts prepared, management has assumed that the Group will continue to operate within both available and prospective facilities. Accordingly, the Group financial statements are prepared on the going concern basis and do not include any adjustments that would be required in the event that the loan holders do request repayment and alternative finance is not available.

2. Summary of significant accounting policies

Business Combinations

The Group uses the acquisition method of accounting to account for business combinations. The consideration transferred for the acquisition of a subsidiary is the fair values of the assets transferred, the liabilities incurred and the equity interests issued by the Group. The consideration transferred includes the fair value of any asset or liability resulting from a contingent consideration arrangement. Acquisition-related costs are expensed as incurred. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. On an acquisition-by-acquisition basis, the Group recognises any non-controlling interest in the acquiree either at fair value or at the non-controlling interest's proportionate share of the acquiree's net assets.

The excess of the consideration transferred, the amount of any non-controlling interest in the acquiree and the acquisition-date fair value of any previous equity interest in the acquiree over the fair value of the Group's share of the identifiable net assets acquired is recorded as goodwill. If this is less than the fair value of the net assets of the subsidiary acquired in the case of a bargain purchase, the difference is recognised directly in profit or loss.

Oil and natural gas exploration, evaluation and development expenditure

Oil and gas exploration activities are accounted for in a manner similar to the successful efforts method. Costs of successful development and exploratory wells are capitalised.

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.

Property, plant and equipment, Mineral rights and other intangibles

Oil and gas properties and other property, plant and equipment, including mineral rights are stated at cost, less accumulated depletion, depreciation and accumulated impairment losses.

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, 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 and Depletion

Oil and gas properties are depreciated on a unit-of-production basis over proved developed reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. Mineral rights are depleted on the unit-of-production basis over proved and probable reserves of the relevant area.

Other property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives as follows:

	years
Buildings and constructions	30-50
Other property, plant and equipment	1-6

Major maintenance and repairs

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalized. Where part of the asset was not separately considered as a component, the replacement value is used to estimate the carrying amount of the replaced assets which is immediately written off. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. All other maintenance costs are expensed as incurred.

Intangible assets

Intangible assets are stated at the amount initially recognised, less accumulated amortization and accumulated impairment losses. Intangible assets include computer software.

Intangible assets acquired separately are measured on initial recognition at cost. The cost of intangible assets acquired in a business combination is fair value as at the date of acquisition. Following initial recognition, intangible assets are carried at cost less any accumulated amortization and any accumulated impairment losses. Amortization is calculated on a straight line basis over their useful lives, except for mineral rights that are depleted on the unit-of-production basis as explained above.

Impairment of assets

The Group monitors internal and external indicators of impairment relating to its tangible and intangible assets.

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use ('VIU') calculations and fair values less costs to sell (;FVLCS'). These calculations require the use of estimates and assumptions. It is reasonably possible that the oil price assumption may change which may then impact the estimated life of the field and may then require a material adjustment to the carrying value of long-term assets.

Given the shared infrastructure and interdependency of cash flows related to the three licenses the Group holds, the assets are considered to represent one Cash Generating Unit (CGU), which is the lowest level where largely independent cash flows are deemed to exist.

Share option plan

The share option plan, under which the Group has the ability to choose whether to settle it in cash or equity instruments at the discretion of the Board of Directors is accounted for as an equity settled transaction. The fair value of the options granted by the Parent to employees is measured at the grant date and calculated using the Trinomial option pricing model and recognised in the consolidated financial statements as a component of equity with a corresponding amount recognised in selling, general and administrative expenses over the time share reward vest to the employee.

Modifications of the terms or conditions of the equity instruments granted in a manner that reduces the total fair value of the share-based payment arrangement or is not otherwise beneficial to the employee, are accounted for as services received in consideration for the equity instruments granted as if the modification had not occurred.

Financial instruments

A financial instrument is any contract that gives rise to financial assets or liabilities.

Financial assets within the scope of IAS 39 are classified as either financial assets at fair value through profit or loss, loans and receivables, held to maturity investments, or available for sale financial assets, as appropriate. When financial assets are recognised initially, they are measured at fair value, plus directly attributable transaction costs for all financial assets not carried at fair value through profit or loss.

The Group determines the classification of its financial assets at initial recognition.

Financial instruments carried on the consolidated statement of financial position include loans and receivables, cash and cash equivalent balances, borrowings, accounts payable and put and call options. The particular recognition and measurement methods adopted are disclosed in the individual policy statements associated with each item.

An obligation to acquire own shares is classified as a liability. The liability to repurchase own shares is initially recognised at the fair value of consideration payable (being the net present value of estimated redemption amount) and it is recorded as deduction of equity. Subsequent changes (revision of estimate, unwinding of discount) are recognised in profit or loss. If options are not exercised, the amount recognised as a liability is transferred to equity.

Rights to acquire own shares are classified as assets. The right to repurchase own shares is initially recognised at the fair value of consideration payable, estimated using the Black-Scholes option pricing model, and it is recorded as increase of equity. Subsequent changes (revision of estimate) are recognised in profit and loss. If options are not exercised, the amount recognised as asset is transferred to equity.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement loans and receivables are subsequently carried at amortized cost using the effective interest method less any provision for impairment.

A provision for impairment is recognised when there is an objective evidence that the Group will not be able to collect all amounts due according to the original terms of the loans and receivables. The amount of provision is the difference between the assets' carrying value and the present value of the estimated future cash flows, discounted at the original effective interest rate. The change in the amount of the loan or receivable is recognised in profit or loss. Interest income is recognised in profit or loss by applying the effective interest rate.

Cash and cash equivalents

Cash and cash equivalents in the consolidated statement of financial position comprise cash at banks and on hand and short term deposits with an original maturity of three months or less.

For the purpose of the consolidated cash flow statement, cash and cash equivalents consist of cash and cash equivalents as defined above, net of outstanding bank overdrafts if any.

Borrowings and accounts payable

The Group's financial liabilities are represented by accounts payable and borrowings.

Borrowings are initially recognised at fair value of the consideration received less directly attributable transaction costs. After initial recognition, borrowings are measured at amortized cost using the effective interest method; any difference between the initial fair value of the consideration received (net of transaction costs) and the redemption amount is recognised as an adjustment to interest expense over the period of the borrowings.

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

Impairment of financial assets

The Group assesses at the end of each reporting period whether there is any objective evidence that a financial asset or a group of financial assets is impaired. A financial asset or a group of financial assets is deemed to be impaired if, and only if, there is an objective evidence of impairment as a result of one or more events that has occurred after the initial recognition of the asset (an incurred 'loss event') and that loss event has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated. Evidence of impairment may include indications that the debtors or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganisation and where observable data indicate that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults.

Inventories

Inventories are stated at the lower of cost and net realisable value. Cost of inventory is determined on the weighted average basis. The cost of finished goods and work in progress comprises raw material, direct labour, other direct costs and related production overheads (based on normal operating capacity) but excludes borrowing costs. Net realisable value is the estimated selling price in the ordinary course of business, less the estimated cost of completion and selling expenses.

Provisions

General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The expense relating to any provision is presented in profit or loss net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using rates that reflect, 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 finance costs.

Provision for dismantlement

Provision for dismantlement is related primarily to the conservation and abandonment of wells, removal of pipelines and other oil and gas facilities together with site restoration activities related to the Group's license areas. When a constructive obligation to incur such costs is identified and their amount can be measured reliably, the net present value of future decommissioning and site restoration costs is capitalised within property plant and equipment with a corresponding liability. Provisions are estimated based on engineering estimates, license and other statutory requirements and practices adopted in the industry and are discounted to net present value using discount rates reflecting adjustments for risks specific to the obligation.

Adequacy of such provisions is periodically reviewed. Changes in provisions resulting from the passage of time are reflected in profit or loss each year under finance costs. Other changes in provisions, relating to a change in the expected pattern of settlement of the obligation, changes in the discount rate or in the estimated amount of the obligation, are treated as a change in accounting estimate in the period of the change and are reflected as an adjustment to the provision and a corresponding adjustment to property, plant and equipment. If a decrease in the liability exceeds the carrying amount of the asset, the excess is recognized immediately in profit or loss.

Taxes

Income tax

The income tax expense comprises current and deferred taxes calculated based on the tax rates that have been enacted or substantively enacted at the end of the reporting period. Current and deferred taxes are charged or credited to profit or loss except where they are attributable to items which are charged or credited directly to equity, in which case the corresponding tax is also taken to equity.

Current tax is the amount expected to be paid to or recovered from the taxation authorities in respect of taxable profits or losses for the current and prior periods.

Deferred tax assets and liabilities are calculated in respect of temporary differences using the liability method. Deferred taxes provide for all temporary differences arising between the tax bases of assets and liabilities and their carrying values for financial reporting purposes, except where the deferred tax arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

A deferred tax asset is recognised for all deductible temporary differences and carry forward of unused tax credits and unused tax losses only to the extent that it is probable that taxable profit will be available against which the deductible temporary differences or carry forward losses can be utilised.

Unrecognised deferred tax assets are reassessed at the end of each reporting period 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 tax assets and liabilities are offset when the Group has a legally enforceable right to set off current tax assets and liabilities, when deferred tax balances are referred to the same governmental body (i.e. federal, regional or local) and the same subject of taxation and when the Group intends to perform an offset of its current tax assets and liabilities.

Mineral extraction tax

Mineral extraction tax on hydrocarbons, including natural gas and crude oil, is due on the basis of quantities of natural resources extracted. Mineral extraction tax for crude oil is determined based on the volume produced per fixed tax rate (RUR419 per ton) adjusted depending on the monthly average market prices of the Urals blend and the RUR/US$ exchange rate for the preceding month. The ultimate amount of the mineral extraction tax on crude oil depends also on the depletion and geographic location of the oil field. Mineral extraction tax on gas condensate is determined based on a fixed percentage from the value of the extracted mineral resources. Mineral extraction tax is accrued as a tax on production and recorded within cost of sales.

Equity

Share capital

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares and options are shown in equity as a deduction, net of tax, from the proceeds. Any excess of the fair value of shares issued or liabilities over the par value of shares issued is recorded as share premium.

Other reserves

Other reserves include reserve on reorganisation of the Group .

Non-controlling interests

Non-controlling interests ("NCI") is the equity in subsidiaries not attributable, directly or indirectly, to the parent. NCI at the end of the reporting period represents the non-controlling shareholders' portion of the carrying value of the identifiable assets and liabilities of the subsidiary. NCI are presented within equity, separately from the equity, attributable to the Parent's shareholders .

The Group treats transactions with NCI as transactions with equity owners of the Group. For purchases from NCI the difference between any consideration paid and the relevant share acquired of the carrying value of net assets of the subsidiary is recorded in equity. Gains or losses on disposals to non-controlling interests are also recognised in equity.

Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable for goods provided or services rendered less any trade discounts, value-added tax and similar sales-based taxes after eliminating sales within the Group.

Revenue from sale of crude oil and gas condensate is recognised when the significant risks and rewards of ownership have been transferred to the customer, the amount of revenue can be measured reliably, it is probable that the economic benefits associated with the transaction will flow to the Group and costs incurred or to be incurred in respect of this transaction can be measured reliably. If the Group agrees to transport the goods to a specified location, revenue is recognised when goods are passed to the customer at the designated location.

Other revenue is recognised in accordance with contract terms.

Interest income is accrued on a regular basis by reference to the outstanding principal amount and the applicable effective interest rate, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount. Dividend income is recognized where the shareholders' right to receive a dividend payment is established.

Leases

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the income statement on a straight-line basis over the period of the lease.

Borrowing costs

Borrowing costs directly relating to the acquisition, construction or production of a qualifying capital project under construction are capitalised and added to the project cost during construction until such time the assets are substantially ready for their intended use i.e. when they are capable of production. Where funds are borrowed specifically to finance a project, the amount capitalised represents the actual borrowing costs incurred. Where surplus funds are available for a short term out of money borrowed specifically to finance a project, the income generated from such short term investments is also capitalised and deducted from the total capitalised borrowing cost. Where the funds used to finance a project form part of general borrowings, the amount capitalised is calculated using a weighted average of rates applicable to relevant general borrowings of the Group during the period. All other borrowing costs are recognised in the profit or loss as finance costs in the period in which they are incurred.

Employee benefits

Wages, salaries, contributions to the Russian Federation state pension and social insurance funds, paid annual leave and sick leave, bonuses are expensed as incurred.

Foreign currency translation
Foreign currency transactions are initially recognized in the functional currency at the exchange rate ruling at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the functional currency rate of exchange in effect at the end of the reporting period.

The US dollar ("US$") is the presentation currency of the Group and the functional currency of the Parent Company. The functional currency of subsidiaries operating in the Russian Federation is the Russian Rouble (RUR). The assets and liabilities of the subsidiaries are translated into the presentation currency of the Group at the rate of exchange ruling at the end of each of the reporting periods. Income and expenses for each income statement are translated at average exchange rates (unless this average is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the rate on the dates of the transactions). All the resulting exchange differences are recorded in other comprehensive income.

The US$ to RUR exchange rates were 30.37 and 32.20 as at 31 December 2012 and 31 December 2011, respectively and the average rates for the year ended 31 December 2012 and 2011 were 31.07 and 28.74, respectively. The US$ to GBP exchange rates were 0.62 and 0.65 as at 31 December 2012 and 31 December 2011, respectively and the average rates for the year ended 31 December 2012 and 2011 were 0.63 and 0.62, respectively. The decrease in the US$ to RUR exchange rate for the year ended 31 December 2012 has resulted in a gain of US$23,804 thousand in the consolidated statement of comprehensive income and an adjustment of US$6,061 thousand in Other comprehensive income.

Principles of consolidation

Subsidiaries

Subsidiaries are those entities in which the Group has an interest of more than one half of the voting rights, or otherwise has power to exercise control over their operations. Subsidiaries are consolidated from the date on which control is transferred to the Group and are no longer consolidated from the date that control ceases.

All intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated; unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Where necessary accounting policies for subsidiaries have been changed to ensure consistency with the policies adopted by the Group.

The financial statements of the subsidiaries are prepared for the same reporting year as the Parent, using consistent accounting policies.

3. Significant accounting judgements, estimates and assumptions

In the application of the Group's accounting policies, management is required to make judgements, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources.

The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an on-going basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period or in the period of the revision and future periods if the revision affects both current and future periods.

The most significant areas of accounting requiring the use of the Group's management estimates and assumptions relate to oil and gas reserves; useful economic lives and residual values of property, plant and equipment; impairment of tangible assets; provisions for dismantlement; taxation and allowances.

Subsoil Licences

The Group conducts operations under exploration and production licenses which require minimum levels of capital expenditure and mineral production, timely payment of taxes, provision of geological data to authorities and other such requirements. The current periods of the Group's licenses expire between June 2014 and June 2017.

Regulatory authorities exercise considerable discretion in issuing and renewing licenses and in monitoring licensees' compliance with license terms. The loss of licence would be considered a material adverse event for the Group.

It is management's judgement that each of the three licenses held by the Group will be renewed for the economic lives of the fields which are projected to be up to 2040 (two licenses held by INGA) and 2029 (the license held by Trans-oil). The appraised economic lives of the fields are used as the basis for reserves estimation, depletion calculation and impairment analysis. In making this assessment, management consider that the license held by Trans-oil, which was extended for three years to December 2015, will be further extended. This further extension will be depended on management demonstrating to licensing authorities that associated petroleum gas produced in the course of oil production is being utilised.

Useful economic lives of property, plant and equipment and Mineral rights

Oil and gas properties and mineral rights

The Group's oil and gas properties are depleted over the respective life of the oil and gas fields using the unit-of-production method based on proved developed oil and gas reserves. Mineral rights are depleted over the respective life of the oil and gas fields using the unit-of-production method based on proved and probable oil and gas reserves.

Reserves are determined using estimates of oil in place, recovery factors and future oil prices.

When determining the life of the oil and gas field, assumptions that were valid at the time of estimation, may change when new information becomes available. The factors that could affect the estimation of the life of an oil and gas field include the following:

- Changes of proved and probable oil and gas reserves;
- Differences between actual commodity prices and commodity price assumptions used in the estimation of oil and gas reserves;
- Unforeseen operational issues; and
- Changes in capital, operating, processing and reclamation costs, discount rates and foreign exchange rates possibly adversely affecting the economic viability of oil and gas reserves.

Any of these changes could affect prospective depletion of mineral rights and oil and gas assets and their carrying value.

Other non-production assets

Property, plant and equipment other than oil and gas properties are depreciated on a straight-line basis over their useful economic lives . Management at the end of each reporting period reviews the appropriateness of the assets useful economic lives and residual values. The review is based on the current condition of the assets, the estimated period during which they will continue to bring economic benefit to the Group and their estimated residual value.

Estimation of oil and gas reserves

Unit-of-production depreciation, depletion and amortization charges are principally measured based on Group's estimates of proved developed and proved and probable oil and gas reserves. Estimates of proved and probable reserves are also used in determination of impairment charges and reversals. Proved and probable reserves are estimated by an independent international reservoir engineers, by reference to available geological and engineering data, and only include volumes for which access to market is assured with reasonable certainty.

Estimates of oil and gas reserves are inherently imprecise, require the application of judgements and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms or development plans. Changes to Group's estimates of proved and probable reserves affect prospectively the amounts of depreciation, depletion and amortization charged and, consequently, the carrying amounts of mineral rights and oil and gas properties.

Were the estimated proved reserves to differ by 10% from management's estimates, the impact on depletion would be as follows:

Increase/decrease in reserves estimation	**Effect on loss before tax for the year ended 31 December**	
	2012	**2011**
+ 10%	(1,628)	(2,132)
- 10%	1,989	2,606

Provision for dismantlement

The Group has a constructive obligation to recognize a provision for dismantlement for its oil and gas assets . The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time when assets are installed. The Group performs analysis and makes estimates in order to determine the probability, timing and amount involved with probable required outflow of resources. Estimating the amounts and timing of such dismantlement costs requires significant judgement. The judgement is based on cost and engineering studies using currently available technology and is based on current environmental regulations. Provision for dismantlement is subject to change because of change in laws and regulations, and their interpretation.

Estimated dismantlement costs, for which the outflow of resources is determined to be probable, are recognised as a provision in the Group's financial statements.

Impairment of non-current assets

The Group accounts for the impairment of non-current assets in accordance with IAS 36 Impairment of Assets. Under IAS 36, the Group is required to assess the conditions that could cause assets to become impaired and to perform a recoverability test for potentially impaired assets held by the Group. These conditions include whether a significant decrease in the market value of the assets has occurred, whether changes in the Group's business plan for the assets have been made or whether a significant adverse change in the business environment has arisen.

Subsequent to the year end, the Group's shares have been trading at a level which indicate that the market capitalization of the Group is below the carrying value of net assets. This has resulted in a review of the Group's non-current assets (Oil and Gas properties and Mineral Rights) to determine whether they are impaired as at the reporting date

If there are indications of loss in value, the recoverable amount is estimated. The recoverable amount is the higher of the assets FVLCS, or its VIU. Management consider that an appropriate approach to determining FVLCS is by discounting the post-tax cash flows expected to be generated by the oil and gas assets, net of associated selling costs, taking into account those assumptions that market participants would use in estimating fair value. The VIU is a discounted cash flow calculation based on continued use of the assets in its present condition, excluding potential exploitation of improvement or expansion potential.

The determination of the recoverable amount for both the FVLCS and the VIU involves assumptions as to future hydrocarbon prices, taxes, production volumes, and inflation. The models also use estimates of proved developed for VIU and proved and probable reserves for FVLCS as developed by the independent Reservoir Engineers, DeGolyer and MacNaughton. Estimated cash flows are discounted with a risk adjusted discount rate derived as the weighted average cost of capital (WACC). For the Group's businesses the pre-tax nominal discount rate is estimated at 12%.

Based on our estimation of Fair value less cost of sale, we do not consider that the Group's non-current assets are impaired as of 31 December 2012.

Assumption used in developing cash flow forecasts of the Group

Assumption	Value
Average crude oil price	101 USD per barrel
Average effective rate of mineral extraction tax of crude oil	4,700 RUB per ton
Average effective rate of mineral extraction tax of gas condensate	590 RUB per ton
Production volume of crude oil over economic life of the fields	438,574 thousand barrels
Production volume of gas condensate over economic life of the fields	13,584 thousand barrels
Inflation	5%

As the discounted cash flows calculations are sensitive to changes in discount rate of cash flow and to changes in average crude oil price the amount of discounted cash flows may vary. If discount rate differed by 1% from management's estimates, the impact on discounted cash flows would be to increase it by US$168 million or decrease it by US$149 million. If average crude oil price per barrel differed by US$10 from management's estimates, the impact on discounted cash flows would be to change it by US$309 million.

Taxation

The Group is subject to income and other taxes. Significant judgement is required in determining the provision for income tax and other taxes due to complexity of the tax legislation of the Russian Federation. Deferred tax assets are recognised to the extent that it is probable that it will generate enough taxable profits to utilise deferred income tax recognised. Significant management judgement is required to determine the amount of deferred tax assets recognised, based upon the likely timing and the level of future taxable profits. Management prepares cash flow forecasts to support recoverability of deferred tax assets. Cash flow models are based on a number of assumptions relating to oil prices, operating expenses, production volumes, etc. These assumptions are consistent with those, used by independent reservoir engineers. Management also takes into account uncertainties related to future activities of the Group and going concern considerations. When significant uncertainties exist deferred tax assets arising from losses are not recognised even if recoverability of these is supported by cash flow forecasts.

Segment reporting

Management views the Group as one operating segment and uses reports for the entire Group to make strategic decisions. 98% and 97% of total revenues from external customers in 2012 and 2011 respectively were derived from sales of crude oil and gas condensate. These sales are made to domestic and international oil traders. Although there are a limited number of these traders the Group is not dependent on any one of them as crude oil is widely traded and there are a number of other potential buyers of this commodity. The Group's operations are entirely located in Russia.

Gain on settlement of Makayla Investment Limited liability

Management views the difference between the carrying value of the liability to Makayla Investments Limited and the fair value of shares issued for the settlement of the liability is a gain because in effect the transaction was settled with a third party.

The Parent's Board of directors evaluates performance of the entity on the basis of different measures, including total expenses, capital expenditures, operating expenses per barrel and others (Note 6).

4. Adoption of the new and revised standards

At the date of approval of these consolidated financial statements the following accounting standards, amendments and interpretations were issued by the International Accounting Standards Board and IFRS Interpretations Committee in the year ended 31 December 2012, but are not yet effective and therefore have not been applied:

(i) Not endorsed by the European Union

New standards and interpretations

- IFRS 9 – Financial Instruments (effective for annual periods beginning on or after 1 January 2015).

Management expects that the adoption of these accounting standards in future periods will not have a material effect on the financial statements of the Group.

5. Revenue

	Year ended 31 December	
	2012	**2011**
Revenue from crude oil sales	63,614	37,595
Revenue from gas condensate sales	11,230	-
Other revenue	1,386	1,123
Total Revenue	**76,230**	**38,718**

Other revenue includes proceeds from third parties for crude oil transportation.

For the years ended 31 December 2012 and 2011, revenue from export sales of crude oil amounted to US$16,877 thousand and US$11,120 thousand, respectively.

Revenues from some individual customers in the crude oil and gas condensate segment approximately equalled or exceeded 10% of total Group's segment revenue.

	Year ended 31 December	
Customer	**2012**	**2011**
Customer 1	20,047	23,794
Customer 2	16,877	11,120
Customer 3	16,831	-
Customer 4	8,779	-
Customer 5	7,774	-
	70,308	**34,914**

6. Other income

On 13 December 2011, Itera Group Limited agreed to sell a receivable from Ruspetro relating to deferred consideration arising from the acquisition of INGA and Trans-oil (the 'Itera debt') to Makayla Investments Limited ('Makayla'), a related party and shareholder of the Parent. As at 31 December 2011, Ruspetro had a related liability including accrued interest of US$47,453 thousand recorded in its consolidated financial statements.

Makayla negotiated the terms of settlement with Itera and agreed to buy the receivable at an amount lower than the carrying value. Makayla passed on this benefit to Ruspetro by entering into an agreement dated 13 December 2011 with Ruspetro, granting it the option to acquire the debt owing to Makayla by no later than 25 January 2012 for US$26,171 thousand.

On 18 January 2012, the Parent Company issued 12,707,584 Ordinary Shares at GBP 1.34 each to Makayla to acquire this debt for a total fair value of US$26,171 thousand. Management is of the view that the difference between the carrying value of the liability and the fair value of shares issued is a gain because in effect the transaction was settled with a third party. Accordingly, an amount of US$21,282 thousand representing the difference between the nominal value of the debt and the fair value of the issued ordinary shares was recognised as other in the year.

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7. Income tax

The major components of income tax expense for the years ended 31 December 2012 and 2011 are:

	Year ended 31 December	
	2012	**2011**
Current Income tax expense	-	-
Deferred tax benefit	819	3,602
Total Income tax benefit	**819**	**3,602**

Income tax for the reporting period is calculated in accordance with the policy disclosed in Note 1.

Profit before taxation for financial reporting purposes is reconciled to the tax calculation for the period as follows:

	Year ended 31 December	
	2012	**2011**
Loss before income tax	**(28,103)**	**(88,665)**
Income tax benefit at applicable tax rate	5,621	17,733

	Year ended 31 December	
	2012	**2011**
Tax effect of losses for which no deferred income tax asset was recognized	(9,026)	(18,523)
Tax effect for losses utilised in Russian accounts	333	5,725
Tax effect of share-base payment compensation	(2,407)	-
Tax effect of Sberbank capital share options	(1,129)	-
Tax effect of non-deductible expenses	(2,573)	(1,333)
Income tax (expense) / benefit	**819**	**3,602**

Differences between IFRS and statutory taxation regulations in Russia give rise to temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and their tax bases. The tax effect of the movements in these temporary differences is detailed below and is recorded at the rate of 20% for Group companies incorporated in the Russian Federation.

The movements in deferred tax assets and liabilities relates to the following:

	1 January 2012	Recognised in the Income statement	Exchange differences	**31 December 2012**
Liabilities				
Property, plant and equipment	(6,427)	289	(265)	(6,403)
Mineral rights and intangible assets	(80,300)	50	(4,809)	(85,059)
Accounts payable	682	277	57	1,016
Accounts receivable	319	203	24	546
Deferred income tax liabilities	**(85,726)**	**819**	**(4,993)**	**(89,900)**

	1 January 2011	Recognised in the Income statement	Exchange differences	**31 December 2011**
Liabilities				
Property, plant and equipment	(9,459)	2,565	467	(6,427)
Mineral rights and intangible assets	(85,053)	101	4,652	(80,300)
Accounts payable	580	596	(494)	682
Accounts receivable	(51)	340	30	319
Deferred income tax liabilities	**(93,983)**	**3,602**	**4,655**	**(85,726)**

The Group did not recognise deferred income tax assets of US$37,180 thousand and US$38,935 thousand, in respect of losses that can be carried forward against future taxable income amounting to US$185,899 thousand and US$194,675 thousand as at 31 December 2012 and 31 December 2011, respectively. Losses amounting to US$65,687 thousand, US$43,020 thousand, US$28,990 thousand and US$43,858 thousand expire in 2018, 2019, 2020, 2021 respectively.

8. Property, plant and equipment

	Oil & gas properties	Other property, plant and equipment	Construction in progress	**Total**
Cost as at 1 January 2012	**106,324**	**2,632**	**38,432**	**147,388**
Additions	-	-	127,104	127,104
Transfers to fixed assets	97,999	8,332	(106,331)	-
Change in provision for dismantlement	665	-	-	665
Disposals	(926)	(79)	(155)	(1,160)
Effect of translation to presentation currency	8,355	454	2,153	10,962
Cost as at 31 December 2012	**212,417**	**11,339**	**61,203**	**284,959**
Accumulated depletion and impairment as at 1 January 2012	**(34,957)**	**(1,118)**	-	**(36,075)**
Charge for the period	(17,452)	(1,839)	-	(19,291)
Disposals	426	65	-	491
Effect of translation to presentation currency	(3,194)	(154)	-	(3,348)
Accumulated depletion and impairment as at 31 December 2012	**(55,177)**	**(3,046)**	-	**(58,223)**
Net book value as at 31 December 2012	**157,240**	**8,293**	**61,203**	**226,736**

	Oil & gas properties	Other property, plant and equipment	Construction in progress	**Total**
Cost as at 1 January 2011	**78,502**	**2,877**	**31,800**	**113,179**
Additions	-	-	40,751	40,751
Transfers to fixed assets	33,091	191	(33,282)	-
Change in provision for dismantlement	1,727	-	-	1,727
Disposals	-	(42)	(281)	(323)
Effect of translation to presentation currency	(6,996)	(394)	(556)	(7,946)
Cost as at 31 December 2011	**106,324**	**2,632**	**38,432**	**147,388**
Accumulated depletion and impairment as at 1 January 2011	**(14,835)**	**(727)**	-	**(15,562)**
Charge for the period	(23,454)	(551)	-	(24,005)
Disposals	-	24	-	24
Effect of translation to presentation currency	3,332	136	-	3,468
Accumulated depletion and impairment as at 31 December 2011	**(34,957)**	**(1,118)**	-	**(36,075)**
Net book value as at 31 December 2011	**71,367**	**1,514**	**38,432**	**111,313**

For the year ended 31 December 2012, additions to Construction in progress are primarily made up of additions to production facilities, including wells as well as additions to infrastructure. As at 31 December 2012, the construction in progress balance mainly represents exploration and production wells and oil production infrastructure not finalized (e.g. pads, electricity grids, etc.).

None of the Group’s property, plant and equipment was pledged as at the reporting dates.

9. Mineral rights and other intangibles

	Mineral rights	Other intangible assets	**Total**
Cost as at 1 January 2012	**402,351**	**53**	**402,404**
Additions	-	266	266
Effect of translation to presentation currency	24,139	1	24,140
Cost as at 31 December 2012	**426,490**	**320**	**426,810**
Accumulated depletion and impairment as at 1 January 2012	**(855)**	**(36)**	**(891)**
Charge for the period	(452)	(19)	(472)
Effect of translation to presentation currency	102	1	104
Accumulated depletion and impairment as at 31 December 2012	**(1,205)**	**(54)**	**(1,259)**
Net book value as at 1 January 2012	401,496	17	401,513
Net book value as at 31 December 2012	**425,285**	**266**	**425,551**

	Mineral rights	Other intangible assets	Total
Cost as at 1 January 2011	**425,032**	**47**	**425,079**
Additions	-	9	9
Effect of translation to presentation currency	(22,681)	(3)	(22,684)
Cost as at 31 December 2011	**402,351**	**53**	**402,404**
Accumulated depletion and impairment as at 1 January 2011	**(423)**	**(22)**	**(445)**
Charge for the period	(502)	(17)	(519)
Effect of translation to presentation currency	70	3	73
Accumulated depletion and impairment as at 31 December 2011	**(855)**	**(36)**	**(891)**
Net book value as at 1 January 2011	424,609	25	424,634
Net book value as at 31 December 2011	**401,469**	**17**	**401,513**

Intangible assets of the Group are not pledged as security for liabilities and their titles are not restricted.

10. Borrowings

	31 December	
	2012	**2011**
Current		
Sberbank	2,469	45,000
Short-term loans from shareholders of the Parent	19,335	1,197
Total current borrowings	**21,804**	**46,197**

	31 December	
	2012	**2011**
Non-current		
Sberbank	286,671	287,116
Long-term loans from shareholders of the Parent	61,822	73,134
Total long-term borrowings	**348,493**	**360,250**

Sberbank credit facility The Group has a non-revolving US$ denominated credit facility from Sberbank which had the following terms at the date of obtaining the credit facility: a limit of US$250,000 thousand expiring in 2013 with an annual interest rate of 14%. The Parent has pledged all its shares in INGA and Trans-oil as part of the terms of the credit facility.

In 2010, the annual interest rate on the facility was reduced to 9%, increasing to 10.9% from 1 October of that year.

On 25 November 2011, the terms of Sberbank's credit facility were amended whereby, inter alia, repayments of a portion of accrued interest and its principal were deferred until April 2015, and future accrued interest is to be payable half-yearly in May and November of each year. These amendments did not substantially alter the terms of the original credit facility, and were therefore not treated as extinguishment of an existing liability and recognition of a new liability. The present value difference arising from the amendments was recognised over the remaining life of the instrument by adjusting the effective interest rate.

According to the Amended Agreement, on 3 February 2012 Ruspetro paid a portion of the accrued interest, which amounted to US$27,055 thousand together with US$17,945 thousand of principal, with further repayments of outstanding interest of US$10,639 thousand and US$12,618 thousand made on 25 May 2012 and on 26 November 2012, respectively.

The Group recognised a net foreign exchange gain amounting to US$19,512 thousand and a net foreign exchange loss amounting to US$20,439 thousand during the years ended 31 December 2012 and 2011 respectively on the Sberbank credit facility and outstanding accrued interest which is denominated in US$.

Loans from shareholders of the Parent The Group has a number of US$ denominated loans obtained from the Shareholders of the Parent. All of these loans are unsecured and the interest rate on most of these loans is Libor +10% per annum. Certain loans have matured by 31 December 2012 and are presented as current liabilities as at this date.

On 17 January 2012, the Parent and one of the shareholders agreed that the Parent will issue new Ordinary Shares to that shareholder on the date that is 13 months from the date of Admission in full settlement of a loan obtained from the shareholder. On 18 February 2013, a decision was taken not to proceed with the conversion.

11. Provision for dismantlement

The provision for dismantlement represents the net present value of the estimated future obligations for abandonment and site restoration costs which are expected to be incurred at the end of the production lives of the oil and gas fields which is estimated to be in 21 years from 31 December 2012.

	2012	**2011**
As at 1 January	**5,961**	**4,155**
Additions for new obligations and changes in estimates	665	1,727
Unwinding of discount	682	494
Effect of translation to presentation currency	389	(415)
As at 31 December	**7,697**	**5,961**

This provision has been created based on the Group management's internal estimates. Assumptions, based on the current economic environment, have been made which management believe are a reasonable basis upon which to estimate future dismantlement liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual dismantlement costs will ultimately depend upon future market prices for the necessary dismantlement works required which will reflect market conditions at the relevant time. Furthermore, the timing is likely to depend on when the fields cease to produce at economically viable levels. This in turn will depend upon future oil and gas prices and future operating costs which are inherently uncertain.

12. Loss per share

Basic

Basic earnings per share are calculated by dividing the profit attributable to equity holders of the Parent by the weighted average number of ordinary shares in issue during the period.

For comparability, weighted average number of ordinary shares in issue for the year ended 31 December 2011 presented as if the Parent was the Group company in the 2011. For calculation of number of shares outstanding in 2011 the number of shares issued on reorganisation was used.

	Year ended 31 December	
	2012	**2011**
Loss attributable to equity holders of the Parent / Previous parent	27,284	81,095
Weighted average number of ordinary shares in issue	315,539,05	196,890,00

	3	0
Basic Loss per share (US$)	0.09	0.41

Diluted

Diluted earnings per share is calculated by adjusting the weighted average number of ordinary shares to assume conversion of all dilutive potential ordinary shares.

The Parent has incurred a loss from continuing operations for the year ended 31 December 2012 and the effect of considering the exercise of the options on the Parent's shares would be anti-dilutive, that is, it would reduce the loss per share.