LUNDIN PETROLEUM – PRESS RELEASE

Lundin Petroleum AB (publ)
Hovslagargatan 5
SE-111 48 Stockholm
Tel: +46-8-440 54 50, Fax: +46-8-440 54 59, E-mail: info@lundin.ch
Visit our website: www.lundin-petroleum.com

Company registration number 556610-8055

NASDAQ OMX Stockholm : LUPE
Toronto Stock Exchange (TSX): LUP

Stockholm 5 February 2014

YEAR END REPORT 2013

HIGHLIGHTS

Fourth quarter ended 31 December 2013 (31 December 2012)
- Production of 31.1 Mboepd (35.9 Mboepd)
- Revenue of MUSD 288.2 (MUSD 346.9)
- EBITDA of MUSD 218.6 (MUSD 289.8)
- Operating cash flow of MUSD 204.8 (MUSD 237.4)
- Net result of MUSD 23.0 (MUSD -52.7)

Twelve months ended 31 December 2013 (31 December 2012)
- Production of 32.7 Mboepd (35.7 Mboepd)
- Revenue of MUSD 1,195.8 (MUSD 1,375.8)
- EBITDA of MUSD 960.9 (MUSD 1,144.1)
- Operating cash flow of MUSD 975.6 (MUSD 831.4)
- Net result of MUSD 72.9 (MUSD 103.9)
- Net debt of MUSD 1,182 (MUSD 335)
- Oil discovery in PL359 Luno II, offshore Norway
- Gohta oil discovery in the Barents Sea, Norway
- Heads of Agreement signed with Rosneft for the sale of a 51 percent interest in the Lagansky Block, Russia

	1 Jan 2013- 31 Dec 2013 12 months	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Production in Mboepd	32.7	31.1	35.7	35.9
Revenue in MUSD	1,195.8	288.2	1,375.8	346.9
Net result in MUSD	72.9	23.0	103.9	-52.7
Net result attributable to shareholders of the Parent Company in MUSD	77.6	23.7	108.2	-51.5
Earnings/share in USD[1]	0.25	0.08	0.35	0.21
EBITDA in MUSD	960.9	218.6	1,144.1	289.8
Operating cash flow in MUSD	975.6	204.8	831.4	237.4

[1] Based on net result attributable to shareholders of the Parent Company

Lundin Petroleum is a Swedish independent oil and gas exploration and production company with a well balanced portfolio of world-class assets primarily located in Europe and South East Asia. The Company is listed at the NASDAQ OMX, Stockholm (ticker "LUPE") and at the Toronto Stock Exchange (TSX) (Ticker "LUP"). Lundin Petroleum has proven and probable reserves of 194 million barrels of oil equivalent (MMboe).

LETTER TO SHAREHOLDERS

Dear fellow Shareholders,
I am very excited about the prospects for Lundin Petroleum as we embark on another year. Our primary objective remains that of building long term and sustainable value for our shareholders. In that respect we continue to be primarily focused upon the discovery of new hydrocarbon resources through our exploration drilling activities. This strategy has delivered extremely positive results over the past ten years and I remain confident that we have the licences, people and financial resources to continue to find new fields with the materiality to have a positive impact on our valuation. Our 2014 exploration work programme, with particular focus on the Barents Sea, offshore Norway and offshore Sabah, Malaysia, is most prospective in my opinion.

As Lundin Petroleum grows we continue to mature our development and operational capabilities. Our four development projects in Norway are progressing well overall and we remain confident of achieving significant growth in our production, operating cash flow and profitability over the next few years. We forecast our average production will reach approximately 50,000 barrels of oil equivalent per day (boepd) in 2015 and indeed will increase to over 75,000 boepd by the end of 2015 when Edvard Grieg comes onstream. We are pleased with the progress on our projects and as we approach first oil the execution risks are reducing.

Financial Resources sufficient to fund activities for foreseeable future
The primary source of funding for our development, appraisal and exploration programmes is operating cash flow from our existing production. Our current production activities are Brent oil dominated with low operating costs and cash taxes which therefore generate high operating cash flow. An operating cash flow net back[1] of USD 81.70 per barrel was achieved in 2013 generating operating cash flow of close to USD 1 billion. I expect this to continue in 2014 with operating cash flow in excess of USD 1 billion.

Our other source of funding is bank borrowings. We have excellent support from our 25 international banks which have provided a USD 2.5 billion revolving credit facility to fund our ongoing development and exploration activities. We have recently taken the opportunity to increase our credit facility to USD 4 billion which has been supported by all our existing lenders. This larger facility will improve our financial flexibility as the Johan Sverdrup development expenditures start to be incurred and allow us to continue our aggressive exploration programmes. We are now fully funded for the foreseeable future with sufficient contingency to deal with unforeseen circumstances.

Production to increase to over 75,000 boepd from ongoing projects
Our production for 2013 averaged 32,700 boepd which was close to the lower end of our original production guidance. In general our production assets performed in accordance with our expectations with the exception of the Brynhild development where first oil has been delayed until the second quarter of this year. Our production forecast for 2014 is between 30,000 and 35,000 boepd with the declines from our existing fields offset by the new production from Brynhild. As I mentioned earlier, our 2015 production will increase to over 50,000 boepd with the start-up of production from the Bøyla, Bertam and Edvard Grieg fields in 2015.

Development projects on track
We have made good progress over recent months on all our development projects.

I believe that the frustrating delays to our Brynhild project are behind us and that we can achieve our second quarter first oil forecast. The subsea installation work was completed last year. The modification work on the Haewene Brim FPSO has now been substantially completed and the vessel is now back on location at the Shell operated Pierce field in the UK North Sea. The new riser installation work will commence shortly to allow the commencement of Brynhild production. The development drilling on Brynhild is continuing and has been adversely impacted by the recent North Sea weather but should not have any adverse impact on first oil timing.

Following approval of the Bertam development project offshore Malaysia in 2013, we are encouraged by the progress on Bertam. The contract for the offshore platform has been awarded to Malaysian yard TH Heavy Engineering (THHE) and construction activities are now ongoing. The Bertam project will also utilise our 100 percent owned Ikdam FPSO which was redeployed to Malaysia following the cessation of production from our Oudna field, offshore Tunisia. The modification of the Ikdam FPSO to enable the vessel to be fit for purpose for Bertam is ongoing at the Keppel shipyard in Singapore. Development drilling on Bertam will commence later this year. First oil from Bertam is expected in the first half of 2015.

We are also making good progress with the Edvard Grieg project. The jacket is substantially complete and will be installed on location this summer when pre-drilling of development wells will commence. The procurement for all topside equipment is complete and construction activities are advancing satisfactorily. The project remains on budget and schedule for first oil in late 2015.

Appraisal - Johan Sverdrup a unique asset
The appraisal of the Johan Sverdrup field is substantially complete. The working operator Statoil recently announced an updated full field resource estimate of between 1.8 and 2.9 billion barrels of oil equivalent and that first oil was forecast for late 2019. I expect the field partners to formally approve the Johan Sverdrup concept selection in the near future. I know it has been frustrating for many shareholders waiting for information on the development concept. However this is a huge project and it is important that the right

[1] Net back: Operating cash flow divided by total production volume

investments are made today to maximise long term value. This has been done and I believe all Johan Sverdrup partners are fully aligned in this respect. It is extremely exciting to be a material partner in this project as it takes shape. The quality, location and size of Johan Sverdrup are unique for any company, not just Lundin Petroleum, and will ultimately deliver material long term value.

It is sometimes easy with the size of Johan Sverdrup to forget the rest of our appraisal portfolio. Over the last couple of years we have had exploration discoveries at Luno II and Gohta in Norway and Tembakau offshore Malaysia. We will be drilling appraisal wells on all these discoveries in 2014 with potential to almost double our existing reserves. None of our production forecasts assume any contribution from these potential developments.

Exploration - Barents Sea to grow in importance.
I have received comments recently that Lundin Petroleum is no longer an exploration focused company and that we no longer have any material exposure through our drilling programme. Very simply this is inaccurate on both counts.

We announced late last year our 2014 exploration programme which will expose us to over 600 million barrels of oil equivalent exposure during the year. I reiterate exploration remains a key focus for us not only this year but for the foreseeable future.

In Norway we believe that there are more hydrocarbons to be found in the Utsira High. We are at the forefront of exploration activity in the region and still have the largest acreage position as this area develops infrastructure with the Edvard Grieg and Johan Sverdrup developments proceeding. We are also very excited with progress in the Barents Sea which we see emerging as an oil producing province in the next few years. There have been a number of important discoveries in the Barents Sea in recent months including our Gohta success and we see a marked increase in activity in the region from the industry. Our acreage position is already significant and I was pleased that we were recently awarded an additional four blocks in the recent APA 2013 round. Our objective is to be at the forefront of exploration activity in the Barents Sea in the next five years where we think there is the potential to discover large new oil resources.

Similarly in South East Asia, 2014 will be a busy year. Our strategy to acquire new 3D seismic in areas overlooked by the majors in recent years has already yielded positive results with Bertam moving into development and Tembakau likely to be developed. We will be drilling in Sabah this year where we believe there is potential to make large oil discoveries close to existing infrastructure. However we are also enhancing our portfolio in frontier areas such as the Cendrawasih VII licence in eastern Indonesia which contains some very exciting structures which we hope to drill in 2015.

Oil Markets
As we have forecast, Brent oil prices have remained comfortably above USD 100 per barrel and I personally expect this to continue. The shale oil revolution in the United States continues to deliver increased oil supplies but geopolitical uncertainty in the Middle East and North Africa continues to have a negative impact on supply. The Chinese economy has slowed but growth levels still remain high with continued strong commodity demand including oil. This Chinese demand coupled with, in my view, better demand than forecast from the developed world will ensure that oil prices remain firm.

Prices will also be supported by the high levels of cost prevalent in our industry which over recent years have squeezed profitability margins. The level of cost inflation we have experienced over the last 10 years is not sustainable and will have an impact on future production as certain projects are deemed uneconomic.

In summary, Lundin Petroleum is in an excellent position. We are fully funded with exposure to major projects such as Johan Sverdrup with Brent oil exposure in low political risk areas and which will produce for many years to come. The long term investments we are making today will in my opinion deliver long term increases in value to our shareholders. I thank you for your confidence and continued support.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 5 February 2014

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon two core areas, Norway and South East Asia. Lundin Petroleum also has assets in France, The Netherlands and Russia. Norway continues to represent the majority of Lundin Petroleum's operational activities with production for the twelve month period ended 31 December 2013 (reporting period) accounting for 73 percent of total production and with 76 percent of Lundin Petroleum's total reserves as at the end of 2013.

RESERVES AND RESOURCES

Lundin Petroleum has 194.1 million barrels of oil equivalent (MMboe) of reserves at the end of 2013 as certified by an independent third party. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. Excluding the major Johan Sverdrup field in Norway, the best estimate contingent resources net to Lundin Petroleum amount to 342 MMboe as at the end of 2013. The Johan Sverdrup field contains gross contingent resources of between 1,800 and 2,900 MMboe as disclosed by pre-unit operator Statoil. The Johan Sverdrup field is situated in licenses PL501, PL502 and PL265 in Norway. Lundin Petroleum has a 40 percent interest in PL501 and a 10 percent interest in PL265.

PRODUCTION

Production for the reporting period amounted to 32.7 thousand barrels of oil equivalent per day (Mboepd) (compared to 35.7 Mboepd over the same period in 2012) and was comprised as follows:

Production in Mboepd	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Crude oil				
Norway	20.6	19.3	23.3	22.9
France	2.9	3.0	2.8	2.8
Russia	2.3	2.1	2.7	2.5
Tunisia	–	–	0.1	–
Total crude oil production	**25.8**	**24.4**	28.9	28.2
Gas				
Norway	3.3	3.2	3.9	4.2
Netherlands	2.0	2.0	1.9	1.8
Indonesia	1.6	1.5	1.0	1.7
Total gas production	**6.9**	**6.7**	6.8	7.7
Total production				
Quantity in Mboe	**11,939.6**	**2,859.9**	13,050.4	3,300.8
Quantity in Mboepd	**32.7**	**31.1**	35.7	35.9

NORWAY

Production

Production in Mboepd	Working Interest (WI)	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Volund	35%	12.2	11.1	13.1	12.5
Alvheim	15%	10.5	10.5	11.8	11.9
Gaupe	40%	1.2	0.9	2.3	2.7
		23.9	**22.5**	27.2	27.1

The Volund field production during the reporting period has exceeded forecast due to better than expected performance of the reservoir and the Alvheim FPSO uptime. An additional Volund development well was drilled in 2012 and put onstream early in 2013 resulting in Volund continuing to produce at close to full flowline capacity. Water breakthrough has now occurred in all of the four producing wells on Volund with total field water cut as at the end of 2013 being approximately 35 percent. The fourth quarter production from Volund was below expectations due to higher water cut development than had been previously forecast. The cost of operations, excluding project specific costs, for the Volund field during the reporting period was below USD 2.50 per barrel.

Production from the Alvheim field during the reporting period was below expectations. This was due to the shut-in of three production wells due to well integrity issues in two of the wells, both of which were shut-in during January 2013, and a flowline integrity issue in a well which was shut-in in June 2013. The flowline integrity issue has been resolved with the well coming back onstream in September 2013. Work-over activity commenced on the remaining two shut-in wells during the fourth quarter 2013. The two worked-over wells are expected to be brought back onstream in February 2014. Maintenance work on the Alvheim FPSO was successfully completed during the planned shut-in in August 2013. There was no production shut-in on the Alvheim FPSO during the comparative period. The Alvheim FPSO uptime levels for the reporting period of close to 96 percent have had a positive impact on the Alvheim production against forecast. The cost of operations for the Alvheim field, excluding well intervention and other one-off related project work, was around USD 5.00 per barrel during the reporting period. The one-off well intervention work during 2013 is being recorded as additional cost of operations and is forecast to account for USD 1.25 of Lundin Petroleum's total cost of operations for the full year. Three infill development wells are scheduled to be drilled on Alvheim in 2014 and 2015 resulting in an expected increase of net reserves in Alvheim for the ninth consecutive year. The previously announced drilling of the North Kameleon exploration prospect north of the Alvheim field is now expected to take place in 2015 due to delays in the Transocean Winner rig schedule.

Production from the Gaupe field during the reporting period has been in line with expectations and the production shut-in during August 2013 for planned maintenance also progressed as expected with the field re-commencing production in September 2013. The Gaupe field is expected to cease production in 2014.

Development

Licence	Field	WI	PDO Approval	Estimated gross 2P reserves	First production expected	Gross plateau production rate expected
PL148	Brynhild	90%	November 2011	23 MMboe	Second quarter 2014	12.0 Mboepd
PL340	Bøyla	15%	October 2012	22 MMboe	First quarter 2015	19.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	186 MMboe	Late 2015	100.0 Mboepd

Brynhild

The Brynhild field installation of the subsea template and manifolds, as well as the installation of production and injection flow lines, have been successfully completed. The drilling of the first of four development wells has reached final target depth and the well has found both the top of the reservoir and the quality of the reservoir as expected. The Haewene Brim FPSO, which will receive the crude oil from the Brynhild field, is owned by Bluewater and contracted to Shell, the operator of the Pierce field offshore United Kingdom. The FPSO arrived at the dry dock in Scotland in July 2013 for topside modification and life extension work. This work was completed later than planned with the FPSO leaving the yard in November 2013 approximately two months behind schedule. The FPSO was re-moored at the Pierce field location late in 2013 for further installation and commissioning work including the installation of a new production riser. First oil from the Brynhild field is forecast in the second quarter of 2014.

Bøyla

The Bøyla field will be developed as a 28 km subsea tie-back to the Alvheim FPSO with two production wells and one water injection well. Fabrication of the field's subsea structures has commenced and drilling of the three development wells is scheduled to take place in 2014 with the Transocean Winner rig. The first oil date has been revised to the first quarter 2015 due to a delay in the Transocean Winner rig schedule. The Bøyla field development costs remain on budget.

Edvard Grieg

The Edvard Grieg field development is progressing on schedule and on budget. Construction and engineering work on the jacket, topside and export pipelines is ongoing. First oil from the Edvard Grieg field is still expected in late 2015.

All the major contracts for the Edvard Grieg development have been awarded. Kværner has been awarded a contract covering engineering, procurement and construction of the jacket and the topsides for the platform and a contract has been awarded to Rowan Companies for a jack-up rig to drill the development wells. Saipem has been awarded the contract for marine installation. During the reporting period, a plan for installation and operation (PIO) has been submitted to the Ministry of Petroleum and Energy for the 43 km long Edvard Grieg oil pipeline and the 94 km long Edvard Grieg gas pipeline. The pipelines will be jointly owned by the licence partners in Edvard Grieg PL338 and Ivar Aasen (formerly Draupne) PL001B/PL028B/PL242 with Lundin Petroleum having an ownership of 30 percent in the oil pipeline and 20 percent in the gas pipeline. Statoil will be the operator of the pipelines. The oil pipeline will be tied-into the Grane oil pipeline and the gas pipeline will be tied-in to the Sage Beryl gas system in the United Kingdom. Installment of the pipelines will be carried out in the summer of 2014. The jacket construction commenced in 2012 and is now substantially complete and is expected to be shipped offshore in the second quarter of 2014 for installation. The construction of the topside commenced in 2013 and installation is planned during the summer of 2015. An appraisal well is planned to be drilled in the southeastern part of the Edvard Grieg reservoir in the first quarter of 2014 with potential to increase reserves and optimise the location of the Edvard Grieg development wells.

The Edvard Grieg development plan incorporates the provision for the coordinated development solution with the nearby Ivar Aasen field located in PL001B and operated by Det norske oljeselskap ASA (Det norske). The Ivar Aasen development plan was approved by the Norwegian authorities during the first quarter of 2013.

Appraisal

Johan Sverdrup

Lundin Petroleum discovered the Avaldsnes field in PL501 (WI 40%) in 2010. In 2011, Statoil made the Aldous Major South discovery on the neighbouring PL265 (WI 10%). Following appraisal drilling, it was determined that the discoveries were connected and in January 2012 the combined discovery was renamed Johan Sverdrup. During 2013 an appraisal well drilled in PL502 (WI 0%) confirmed that a small portion of the field also extends into PL502.

A total of 20 wells have now been drilled on the Johan Sverdrup field and the appraisal campaign is now substantially complete. Statoil, the pre-unit operator of the field has released an updated gross contingent resource estimate for the Johan Sverdrup field of 1,800 to 2,900 MMboe and a first oil date of late 2019. In order to retain the targeted plan of development (PDO) approval schedule of 2015, a FEED contract was awarded to Aker Solutions in late 2013. A development concept selection is anticipated to be made in early 2014.

During the reporting period, seven appraisal wells have been completed. Five appraisal wells have been drilled on PL501 during the reporting period with results in terms of reservoir thickness and quality as well as oil columns being substantially in line with expectations.

One appraisal well was drilled on PL265 which was production tested from two zones with 1,500 bopd flow test from a lower sandstone layers with interbedded shales and 5,900 bopd from an upper zone with excellent quality Jurassic sandstone. One exploration well and one side track from the successful appraisal well were drilled west of the boundary fault on PL265 but both encountered basement with non-commercial reservoir properties.

One successful appraisal well was also drilled on PL502 during the reporting period.

The following table outlines the drilled wells on Johan Sverdrup in 2013.

2013 appraisal well programme on Johan Sverdrup

Licence	Operator	WI	Well	Spud Date	Gross oil column	Result
PL501	Lundin Petroleum	40%	16/2-16aAT2	December 2012	30m	Successfully completed February 2013 (side track)
PL501	Lundin Petroleum	40%	16/3-5	January 2013	30m	Successfully completed March 2013, Drill Stem Test (DST) completed
PL502	Statoil	0%	16/5-3	February 2013	13.5m	Successfully completed March 2013
PL265	Statoil	10%	16/2-17S	March 2013	82m	Successfully completed June 2013, 2 DST completed
PL501	Lundin Petroleum	40%	16/2-21	May 2013	12m	Successfully completed June 2013
PL501	Lundin Petroleum	40%	16/3-6	June 2013	11.5m	Successfully completed July 2013
PL265	Statoil	10%	16/2-18S Cliffhanger, North	July 2013	0m	Completed in August 2013 (exploration)
PL501	Lundin Petroleum	40%	16/5-4	August 2013	6m	Successfully completed in September 2013
PL501	Lundin Petroleum	40%	16/3-7	October 2013	0m	Completed in November 2013

An appraisal well 16/3-8s on PL501 was spudded in January 2014 and is currently drilling on the Crestal high between wells 16/2-6, 16/2-7 and 16/3-4. The partners on PL265 have agreed to drill an additional appraisal well on Johan Sverdrup in 2014 to the north of the Geitungen discovery well 16/2-12.

Exploration

2013 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Southern NCS						
PL453S	8/5-1	January 2013	Ogna	35%	Lundin Petroleum	Dry
PL495	7/4-3	April 2013	Carlsberg	60%	Lundin Petroleum	Dry

Utsira High						
PL338	16/1-17	February 2013	Jorvik	50%	Lundin Petroleum	Oil discovery – non-commercial
PL359	16/4-6S	April 2013	Luno II	40%	Lundin Petroleum	Oil discovery – gross contingent resources 25 – 120 MMboe
PL544	16/4-7	July 2013	Biotitt	40%	Lundin Petroleum	Dry
PL501	16/2-20 and 16/2-20A	September 2013	Torvastad	40%	Lundin Petroleum	Logging ongoing
Utgard High						
PL330	6608/2-1S	June 2013	Sverdrup	30%	RWE Dea	Dry
Barents Sea						
PL492	7120/1-3	July 2013	Gohta	40%	Lundin Petroleum	Oil and Gas discovery – gross contingent resources 105 – 235 MMboe
PL659	7222/11-2	January 2014	Langlitinden	20%	Det norske	Currently drilling

The completion of the well 16/4-6S targeting the Luno II prospect in PL359 (WI 40%) was announced in May 2013 as an oil discovery. The well was drilled on the southwestern flank of the Utsira High approximately 15 km south of the Edvard Grieg field. Lundin Petroleum estimated that the Luno II structure, which is believed to span across two separate reservoir segments, contains gross contingent resources of 25 to 120 MMboe as well as gross prospective resources of 10 to 40 MMboe for the Luno II North segment. The contingent resources relate to the southern segment of the Luno II structure and the prospective resources to the northern segment. Late in 2013, the potential Luno II discovery extension into PL410 (WI 70%) was appraised by well 16/5-5 but the well found the reservoir shallower than expected with worse reservoir quality and lower oil saturation than expected. The extension is therefore regarded as non-commercial. The 25 to 120 MMboe resource range is prior to the drilling of the 16/5-5 appraisal well in PL410. A second Luno II appraisal well is planned to be drilled on PL359 during the first half of 2014. The Luno II North prospect on PL359 to the north of the Luno II discovery is also expected to be drilled during 2014 and in addition to the Luno II North prospect is also planned to target the 23 MMboe Fignon Miocene exploration prospect.

In September 2013, Lundin Petroleum announced a significant oil and gas discovery in the Barents Sea called Gohta. Well 7120/1-3, drilled on PL492 (WI 40%) approximately 35 km north of the Snøhvit field, encountered a 100 metre gross hydrocarbon column in Permo-Carboniferous carbonate reservoir of which the top 25 metres consisted of gas. The well was production tested and achieved a better than expected flow rate of 4,300 bopd through a 44/64" choke with a gas to oil ratio of 1,040 scf/bbl, confirming good production properties from the reservoir. The Gohta discovery is estimated to contain gross contingent resources of 105 to 235 MMboe. The Gohta discovery is likely sourced from a local Triassic oil kitchen which upgrades other prospects on PL492 and adjoining acreage PL609 (WI 40%) to the north. One appraisal well is planned to be drilled on Gohta and one exploration well on the Alta prospect on PL609 in 2014.

To the east of the Gohta discovery, the Langlitinden prospect, operated by Det norske, on PL659 (WI 20%) located to the southeast of the Loppa High spudded in January 2014. The Langlitinden prospect is estimated to contain gross unrisked prospective resources of 220 MMboe.

In October 2013, well 6608/2-1S drilled on PL330 (WI 30%) and operated by RWE Dea Norge AS was announced as a dry hole. The well was targeting Jurassic sandstones in the Sverdrup prospect (not to be confused with the Johan Sverdrup discovery in the North Sea) in the northern Norwegian Sea. The well encountered an active petroleum system but failed to encounter any reservoir and was plugged and abandoned.

In December 2013, well 16/2-20S targeting the Torvastad prospect on PL501 (WI 40%) on the Utsira High was completed. The well found good quality Jurassic reservoir but the reservoir was deep to prognosis and therefore waterbearing. The well was announced as a dry hole. A side-track to the 16/2-20S well to the west was commenced in December to ascertain whether the good quality sand would extend up-dip to the west. The side track did encounter a reservoir section up-dip but with poor reservoir quality. Wireline logging is ongoing.

Lundin Petroleum plans to drill seven exploration wells in Norway during 2014. In addition to the Kopervik, Alta, Langlitinden and Luno II/Fignon exploration wells, further wells are planned to be drilled on the Storm, Lindarormen and Vollgrav prospects. The Storm prospect on PL555 (WI 60%), located in the northern North Sea, is planned to be drilled during the first quarter 2014. In the second half of 2014, the Lindarormen well on PL584 (WI 60%) is forecast to be drilled in the Norwegian Sea to the south of the Asgard field and to the southwest of the Draugen field. In the second half of 2014, the Vollgrav well on PL631 (WI 60%) is also planned to be drilled in the northern North Sea between the Statfjord and Gullfaks fields.

Licence awards and relinquishments
During the reporting period, Lundin Petroleum was awarded seven licences through the APA 2012 licensing round and one additional licence in the 22nd Norwegian licensing round. Four licences were relinquished during the reporting period. In January 2014, it was announced that Lundin Petroleum had been awarded nine licences through the APA 2013 licensing round, including four new licences in the Barents Sea. In January 2014, Lundin Petroleum farmed-out ten percent in PL546 (WI 50% after farm-out) to Petrolia Norway AS.

CONTINENTAL EUROPE

Production

Production in Mboepd	WI	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
France					
- Paris Basin	100%[1]	2.5	2.6	2.3	2.3
- Aquitaine	50%	0.4	0.4	0.5	0.5
Netherlands	Various	2.0	2.0	1.9	1.8
		4.9	**5.0**	4.7	4.6

[1] Working interest in the Dommartin Lettree field 42.5 percent

France
Overall production levels from France during the reporting period have increased with good production from the Grandville field in the Paris Basin which continues to ramp up production from increased water injection capacity and a higher well stock. This increase is partially offset by a production underperformance from certain Aquitaine Basin fields related to various, non-reservoir related, mechanical failures. The Hoplites exploration well on the Est Champagne concession (WI 100%) is planned to be drilled in 2014.

The Netherlands
Production from the Netherlands has been in line with the forecast during the reporting period.

Five exploration wells are planned to be drilled during 2014: one onshore on the Leeuwarden licence (WI 7.23 %), two onshore on the Gorredijk licence (WI 7.75%) and one onshore on the Slootdorp licence (WI 7.23%). One offshore exploration well is planned to be drilled on the E17 licence (WI 1.20%).

SOUTH EAST ASIA

Malaysia
The Bertam oil field, offshore Peninsular Malaysia received development approval from Petronas in October 2013 with first oil expected in 2015. Lundin Petroleum is planning to drill three exploration wells and one appraisal well in Malaysia in 2014.

Offshore, Peninsular Malaysia
Lundin Petroleum holds four licences offshore Peninsular Malaysia with a 75 percent operated working interest in PM307, a 35 percent operated working interest in PM308A, a 75 percent operated working interest in PM308B and a 85 percent operated working interest in PM319. Block PM307 contains the Bertam field and the Tembakau gas discovery.

A field development plan for the Bertam field was approved by Petronas and development commenced during the reporting period. The Bertam field will be developed using a 20 slot Wellhead Platform adjacent to the spread-moored Ikdam FPSO which is owned 100 percent by Lundin Petroleum. The subsurface development concept consists of 13 horizontal wells and one deviated well completed with electrical submersible pumps. The FPSO life extension work contract has been placed with Keppel Shipyard and work is ongoing in Singapore. The wellhead platform contract has been awarded to TH Heavy Engineering (THHE) and work is ongoing at Port Klang close to Kuala Lumpur. Development drilling is planned to commence during the summer of 2014. The total gross capital investment associated with the Bertam field development, excluding any FPSO related costs, is estimated at approximately MUSD 400.

The Bertam field is estimated to contain gross reserves of 18.2 MMboe and is scheduled to commence first oil in 2015 with a gross plateau rate of 15,000 bopd.

A 3D seismic acquisition programme over the northern part of Block PM307 and the southern part of Block PM319 (WI 85%) was completed during the reporting period and processing of the seismic is ongoing. The Tembakau gas discovery made in 2012, with gross best estimate contingent resources of 306 billion cubic feet (bcf), will be appraised as part of the next offshore Peninsular Malaysia drilling campaign to commence in the second quarter of 2014. An exploration well is planned to be drilled on the Rengas oil prospect on PM307 in 2014.

East Malaysia, offshore Sabah
Lundin Petroleum holds two licences offshore Sabah in east Malaysia with a 75 percent operated working interest in Block SB303 and a 42.5 percent operated working interest in Block SB307/308. Block SB303 contains four gas discoveries containing a gross best estimate contingent resource of 347 bcf.

Lundin Petroleum continues to evaluate the potential for commercialisation of the Berangan, Tarap, Cempulut and Titik Terang gas discoveries in Block SB303, most likely through a cluster development. Seismic processing of the 500 km^2 Emerald 3D survey on SB307 was completed during the reporting period and two prospects, Maligan and Kitabu, within the Emerald 3D are planned to be drilled in 2014. An additional 500 km^2 3D seismic acquisition referenced as the Francis 3D, on SB307/308 was completed at the end of July 2013 and processing of the seismic is scheduled to be completed in the first half of 2014.

Indonesia

Lundin Petroleum's assets in Indonesia are located in the Natuna Sea and offshore northeastern Indonesia and onshore south Sumatra. The Indonesian assets consist of approximately 24,750 km^2 of exploration acreage and one producing field onshore Sumatra.

Production

Production in Mboepd	WI	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Singa	25.9%	1.6	1.5	1.0	1.7

The production for the reporting period increased compared to the same period last year following wellhead repairs on the Singa field.

Exploration

Baronang/Cakalang
Exploration drilling on the Baronang Block (WI 90%) is planned to commence in the first quarter of 2014 with a well and a sidetrack targeting the Balqis and Boni prospects with estimated gross prospective resources of 47 MMboe and 55 MMboe respectively. The jack-up rig Hakuryu 11 has been contracted for the purpose of drilling the well and the sidetrack. The rig is currently in Vietnam waiting on weather before being mobilised to Indonesia.

Gurita
Following the completion of the interpretation of the 3D seismic acquisition of 950 km^2 acquired in 2012, the Gobi prospect has been identified as the targeted prospect for the 2014 exploration well on the Gurita Block (WI 90%). The Gobi prospect, which is estimated to contain gross 24 MMboe of prospective resources, is a fault-dip closure on the south flank of the Jemaja High, with stacked closures at multiple levels for Oligocene aged fluvial and alluvial sands which have been proven in many wells in the Natuna Basin. The Gobi prospect is scheduled to be drilled in 2014 immediately following the completion of the drilling of the Balqis and Boni prospects on the Baronang Production Sharing Contract (PSC). In the event that the Hakuryu 11 rig is delayed further in Vietnam there is a risk that the Gobi-1 well is delayed until 2015.

South Sokang
A 3D seismic acquisition programme of 1,000 km^2 has been completed on the South Sokang Block (WI 60%) during the reporting period. The seismic processing and interpretation is schedule to be completed in the first half of 2014.

Cendrawasih VII
In July 2013, Lundin Petroleum announced that it had signed a new PSC with SKKMigas whereby Lundin Petroleum will swap its Sareba Block with a new Block called the Cendrawasih VII Block (WI 100%) offshore eastern Indonesia.

OTHER AREAS

Russia

Production

Production in Mboepd	WI	**1 Jan 2013-31 Dec 2013 12 months**	**1 Oct 2013-31 Dec 2013 3 months**	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months
Onshore Komi Republic	50%	2.3	2.1	2.7	2.5

The production for the reporting period decreased compared to the prior reporting period as a result of the natural decline in the field.

Lagansky Block
In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery, Morskaya, was made in 2008 and is estimated to contain gross best estimate contingent resources of 157 MMboe. In October 2013, Lundin Petroleum announced a Heads of Agreement with Rosneft whereby Rosneft will acquire a 51 percent shareholding in LLC PetroResurs which owns a 100 percent interest in the Lagansky Block. Rosneft's consideration in return for the 51 percent equity stake relates to historical spending on the Block and will be paid to Lundin Petroleum and Gunvor through a deferred payment mechanism. Following the completion of this transaction, Lundin Petroleum will have a 34.3 percent effective interest in the Lagansky Block. It is expected that the Rosneft acquisition will be completed in the first half of 2014.

FINANCIAL REVIEW

Result
The net result for the twelve month period ended 31 December 2013 amounted to MUSD 72.9 (MUSD 103.9). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 77.6 (MUSD 108.2) representing earnings per share of USD 0.25 (USD 0.35).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 960.9 (MUSD 1,144.1) representing EBITDA per share of USD 3.10 (USD 3.68). Operating cash flow for the reporting period amounted to MUSD 975.6 (MUSD 831.4) representing operating cash flow per share of USD 3.15 (USD 2.68).

Changes in the Group
There are no significant changes to the Group for the reporting period.

Revenue
Revenue for the reporting period amounted to MUSD 1,195.8 (MUSD 1,375.8) and comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1. From 1 January 2013, the change in under/over lift position is reported in revenue as stated in the Accounting Policies section below. The comparatives have also been restated for this change.

Net sales of oil and gas for the reporting period amounted to MUSD 1,224.2 (MUSD 1,319.5). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 98.71 (USD 100.89) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 108.66 (USD 111.67) per barrel. The Alvheim and Volund field crude cargoes sold during the reporting period represented 79 percent (76 percent) of the total crude volumes sold and averaged over USD 3.00 per barrel over Dated Brent for the pricing period for each lifting.

Net sales of oil and gas for the reporting period are detailed in Note 3 and were comprised as follows:

Sales Average price per boe expressed in USD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Crude oil sales				
Norway				
– Quantity in Mboe	7,925.4	1,845.7	8,270.1	2,059.4
– Average price per boe	*111.87*	*113.65*	*115.29*	*114.35*
France				
– Quantity in Mboe	1,030.4	233.0	1,041.1	337.9
– Average price per boe	*106.93*	*108.02*	*110.44*	*108.79*
Netherlands				
– Quantity in Mboe	1.8	0.6	1.7	0.5
– Average price per boe	*96.24*	*94.06*	*100.09*	*101.45*
Russia				
– Quantity in Mboe	818.9	184.3	981.6	225.4
– Average price per boe	*77.84*	*76.38*	*77.23*	*79.00*
Tunisia				
– Quantity in Mboe	–	–	227.5	–
– Average price per boe	–	–	*108.14*	–
Total crude oil sales				
– Quantity in Mboe	**9,776.5**	**2,263.6**	10,522.0	2,623.2
– Average price per boe	***108.50***	***110.04***	*110.90*	*109.80*
Gas and NGL sales				
Norway				
– Quantity in Mboe	1,389.4	341.9	1,513.9	467.5
– Average price per boe	*72.33*	*75.46*	*64.18*	*70.35*
Netherlands				
– Quantity in Mboe	715.7	184.5	704.2	169.4
– Average price per boe	*64.34*	*67.24*	*60.18*	*62.92*

Indonesia				
– Quantity in Mboe	520.1	124.0	338.1	113.4
– Average price per boe	*32.54*	*32.79*	*32.43*	*31.73*
Total gas and NGL sales				
– Quantity in Mboe	**2,625.2**	**650.4**	2,556.2	750.3
– Average price per boe	***62.27***	***64.98***	*59.69*	*65.59*
Total sales				
– Quantity in Mboe	**12,401.7**	**2,914.0**	13,078.2	3,373.5
– Average price per boe	***98.71***	***99.98***	*100.89*	*99.97*

The oil produced in Russia is sold on either the Russian domestic market or exported into the international market. 47 percent (45 percent) of Russian sales for the reporting period were on the international market at an average price of USD 108.49 per barrel (USD 109.93 per barrel) with the remaining 53 percent (55 percent) of Russian sales being sold on the domestic market at an average price of USD 50.91 per barrel (USD 49.98 per barrel).

Sales of oil and gas are recognised when the risk of ownership is transferred to the purchaser. Sales quantities in a period can differ from production quantities as a result of permanent and timing differences. Permanent differences arise as a result of paying royalties in kind as well as the effects from production sharing agreements. Timing differences can arise due to under/over lift of entitlement, inventory, storage and pipeline balances effects.

The change in under/over lift position amounted to a charge of MUSD 45.2 (credit of MUSD 30.7) to the income statement and primarily related to Norway where sales volumes were higher than production volumes for the reporting period. Due to the timing of the cargo liftings in relation to the Alvheim Blend sales contract, the volume of oil lifted for the Alvheim and Volund fields was approximately 67 thousand barrels (Mbbl) higher than the production volume during the fourth quarter of 2013.

Other revenue amounted to MUSD 16.8 (MUSD 25.6) for the reporting period and included the quality differential compensation received from the Vilje field owners to the Alvheim and Volund field owners, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France. The comparative period includes MUSD 11.0 relating to an equity redetermination settlement in the Netherlands.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 195.8 (MUSD 203.2) and are detailed in the table below. The comparatives have been restated for the reclassification of the change in under/over lift from production costs to revenue.

Production costs	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Cost of operations				
– In MUSD	114.6	32.6	105.6	29.2
– In USD per boe	9.60	11.39	8.09	8.86
Tariff and transportation expenses				
– In MUSD	25.7	5.8	29.7	8.7
– In USD per boe	*2.15*	*2.05*	*2.27*	*2.63*
Royalty and direct production taxes				
– In MUSD	44.0	10.0	51.3	12.3
– In USD per boe	*3.69*	*3.52*	*3.93*	*3.73*
Change in inventory position				
– In MUSD	-2.0	-1.9	14.8	2.4
– In USD per boe	*-0.16*	*-0.67*	*1.13*	*0.71*
Other				
– In MUSD	13.5	12.1	1.8	0.0
– In USD per boe	*1.12*	*4.19*	*0.14*	*0.00*
Total production costs				
– In MUSD	**195.8**	**58.6**	203.2	52.6
– In USD per boe	***16.40***	***20.48***	*15.56*	*15.93*

Note: USD per boe is calculated by dividing the cost by total production volume for the period.

The total cost of operations for the reporting period was MUSD 114.6 (MUSD 105.6) and included costs associated with well intervention work on two wells on the Alvheim field performed in the fourth quarter of 2013.

The cost of operations per barrel for the reporting period was USD 9.60 (USD 8.09) per barrel and USD 11.39 (USD 8.86) per barrel for the fourth quarter of 2013. The cost of operations per barrel was higher than for the comparative periods for 2012 due mainly to the well intervention work in Norway and France in 2013. The higher cost of operations for the fourth quarter of 2013 of USD 11.39 per barrel compared to the comparative period was due to the Alvheim field well intervention work. This work was ongoing at year end and costs will also be incurred in the first quarter of 2014. Excluding operational projects, the 2013 average cost of operations was USD 7.45 per barrel.

Royalty and direct production taxes amounted to MUSD 44.0 (MUSD 51.3) and included Russian Mineral Resource Extraction Tax (MRET) and Russian Export Duties. The rate of MRET is levied on the volume of Russian production and varies in relation to the international market price of Urals blend and the Rouble exchange rate. MRET averaged USD 23.13 (USD 22.92) per barrel of Russian production for the reporting period. The rate of export duty on Russian oil is revised monthly by the Russian Federation and is dependent on the average price obtained for Urals Blend for the preceding one month period. The export duty is levied on the volume of oil exported from Russia and averaged USD 54.61 (USD 57.08) per exported barrel for the reporting period.

Change in inventory position amounted to a net credit of MUSD 2.0 in the reporting period compared to a net MUSD 14.8 charge in the comparative period. During 2013, there was only one cargo lifting from the Aquitaine fields, France, and the lifting was during the third quarter. In 2012, there were liftings of inventory from the Ikdam FPSO on the Oudna field, Tunisia, which was the main reason for the MUSD 14.8 charge for the comparative period.

Other costs amounted to MUSD 13.5 (MUSD 1.8) and mainly related to a provision recognised for contractual obligations post the expected cessation of production date on the Gaupe field and a mark-to-market valuation of an operating cost share arrangement on the Brynhild field whereby the amount of operating costs varies with the oil price. Both of these items are non-cash and will unwind against actual expenses in the future.

Depletion and decommissioning costs

Depletion charges amounted to MUSD 160.9 (MUSD 186.2) and are detailed in Note 3. Norway's contribution to the total depletion charge for the reporting period was 73 percent at an average rate of USD 13.40 per barrel. The lower depletion charge for 2013 compared to 2012 is line with the lower production volumes and as a result of the lower depletion charge on the Gaupe field following the impairment of the carrying value at 31 December 2012.

Decommissioning costs charged to the income statement in the reporting period amounted to MUSD 13.3 (MUSD 5.2) and primarily related to the increase in the Gaupe field site restoration estimate following the operator's review of the decommissioning timing and cost. The costs reported in the comparative period related to the decommissioning of the Oudna field, Tunisia.

Exploration costs

Exploration costs expensed in the income statement for the reporting period amounted to MUSD 287.8 (MUSD 168.4) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the fourth quarter of 2013, exploration costs of MUSD 135.0 were expensed and mainly related to the costs of drilling the wells on the Sverdrup prospect and Luno II South, Norway on PL330 and PL410 respectively and associated costs, in addition to costs associated with certain licences that were relinquished in Norway during the quarter.

During the first nine months of 2013, MUSD 152.8 was expensed and mainly related to the cost of wells and associated licence costs in Norway together with unsuccessful licence applications in the Norwegian 22nd licensing round.

Impairment costs

Impairment costs expensed in the income statement for the reporting period amounted to MUSD 123.4 (MUSD 237.5) and are detailed in Note 3. The carrying values of oil and gas properties are continuously assessed to ensure recoverability and there were no impairments of oil and gas assets during the fourth quarter of 2013.

The carrying values of the Janglau and Ara discoveries on PM308A, Malaysia, were fully expensed in the third quarter of 2013 for an amount of MUSD 41.7 (MUSD -). During the second quarter of 2013, impairment costs of MUSD 81.7 were expensed in the income statement and mainly related to the gas discoveries on PL438 Skalle, PL533 Salina and PL088 Peik, Norway, which are currently deemed uncommercial.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 43.6 (MUSD 31.8) which included non-cash charges of MUSD 3.3 (MUSD 9.1) in relation to the Group's Long-term Incentive Plan (LTIP) scheme.

The cash charge amounted to MUSD 35.9 (MUSD 19.6) for the reporting period and includes the reallocation of costs previously charged through operations and certain advisory fees including business development activities.

The non-cash charge to the income statement resulting from the LTIP recognised over the reporting period has partly been offset by the reduction in the Lundin Petroleum share price. The provision for the LTIP is calculated based on Lundin Petroleum's share price at the balance sheet date using the Black and Scholes method and is applied to the portion of the outstanding LTIP awards which are recognised at the balance sheet date. Any change in the value of the awards due to a change in the share price impacts all awards recognised at the balance sheet date including those of previous periods with the change in the provision being reflected in the income statement. Lundin Petroleum has mitigated the cash exposure of the LTIP by purchasing its own shares. For more detail refer to the Remuneration section below.

Fixed asset depreciation charges for the reporting period amounted to MUSD 4.4 (MUSD 3.1).

Financial income
Financial income for the reporting period amounted to MUSD 3.3 (MUSD 27.3) and is detailed in Note 4. The comparative period includes a gain on consolidation of a subsidiary of MUSD 13.4 and a net foreign exchange gain of MUSD 6.2.

Financial expenses
Financial expenses for the reporting period amounted to MUSD 86.3 (MUSD 48.5) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 5.3 (MUSD 6.8) and represented the proportion of interest charged to the income statement. An additional amount of interest of MUSD 18.2 (MUSD 3.4) associated with the funding of the Norwegian development projects was capitalised in the reporting period.

Net foreign exchange losses for the reporting period amounted to MUSD 46.5 (MUSD 6.2 gain). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group reporting entities. During the reporting period the US Dollar strengthened against the Norwegian Krona and this has resulted in reported foreign exchange losses. Lundin Petroleum's underlying value is US Dollar based as this is the currency in which the majority of revenues are derived. A strengthening US Dollar currency has a positive overall value effect on the business as it increases the purchasing power of the US Dollar to purchase the currencies in which the Group incurs operational expenditure. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar as detailed in the Derivative financial instruments section below. During the reporting period, the realised exchange gain on settled foreign exchange hedges amounted to MUSD 5.5 (MUSD 11.7).

The amortisation of the deferred financing fees amounted to MUSD 8.7 (MUSD 6.6) for the reporting period and related to the expensing of the fees incurred in establishing the USD 2.5 billion financing loan facility over the period of usage of the facility.

Loan facility commitment fees for the reporting period amounted to MUSD 17.1 (MUSD 10.3). The increase over the comparative reporting period relates to the commitment fees on the undrawn portion of the USD 2.5 billion financing facility entered into in June 2012 compared to the commitment fees on the undrawn portion of the MUSD 850 previous financing facility.

Tax
The overall tax charge for the reporting period amounted to MUSD 215.1 (MUSD 418.4) and is detailed in Note 6.

The current tax charge for the reporting period amounted to MUSD 24.5 (MUSD 341.3) of which MUSD 2.9 (MUSD 311.8) related to Norway. The decrease in the Norwegian tax charge compared to the comparative period is mainly due to the increased level of development and exploration expenditure in Norway as shown in the Non-current assets section below.

The deferred tax charge for the reporting period amounted to MUSD 190.6 (MUSD 77.1) of which MUSD 196.2 (MUSD 80.4) related to Norway. The deferred tax charge arises primarily where there is a difference in depletion for tax and accounting purposes. In addition, previously unrecognised Dutch fiscal unity tax losses were recognised following the field development approval of the Bertam field, Malaysia, resulting in a MUSD 8.9 deferred tax credit in the fourth quarter of 2013. There were also deferred tax credits which totalled MUSD 124.9 in the fourth quarter of 2013 on the Norwegian exploration costs expensed in the fourth quarter, the

Gaupe field post cessation of production obligation provision, the Gaupe field expensed decommissioning costs and the Brynhild operating cost share arrangement provision.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 percent and 78 percent. The effective tax rate for the Group for the reporting period amounted to 75 percent. This effective rate is calculated from the face of the income statement and does not reflect the effective rate of tax paid within each country of operation. The high overall effective rate of tax for the reporting period is largely driven by Norway where the tax rate is 78 percent and that there was not a full tax credit on the impairment costs in Norway, reported during the second quarter and the impairment costs in Malaysia, reported during the third quarter of 2013.

Non-controlling interest
The net result attributable to non-controlling interest for the reporting period amounted to MUSD -4.7 (MUSD -4.3) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

BALANCE SHEET

Non-current assets
Oil and gas properties amounted to MUSD 3,851.9 (MUSD 2,864.4) and are detailed in Note 7.

Development and exploration expenditure incurred for the reporting period was as follows:

Development expenditure in MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Norway	1,105.9	347.9	369.0	133.1
France	7.0	1.5	29.2	2.9
Netherlands	4.8	1.3	8.5	1.7
Indonesia	-1.9	-0.9	-0.4	-0.4
Russia	3.6	1.7	7.5	1.8
Malaysia	12.7	7.9	–	–
	1,132.1	**359.4**	413.8	139.1

An amount of MUSD 1,105.9 (MUSD 369.0) of development expenditure was incurred in Norway during the reporting period, of which MUSD 1,057.2 (MUSD 283.3) was invested in the Brynhild and Edvard Grieg field developments. In Malaysia, MUSD 12.7 (MUSD -) was incurred during the reporting period on the Bertam field development.

Exploration and appraisal expenditure in MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Norway	506.4	116.9	323.2	113.0
France	2.4	0.3	9.8	5.7
Indonesia	18.5	10.7	16.4	3.0
Russia	6.0	2.3	3.6	1.8
Malaysia	36.1	2.9	100.5	40.2
Other	0.5	0.2	3.8	-0.5
	569.9	**133.3**	457.3	163.2

Exploration and appraisal expenditure of MUSD 506.4 (MUSD 323.2) was incurred in Norway during the reporting period.

During the reporting period MUSD 36.1 (MUSD 100.5) was spent in Malaysia on the Ara well on Block PM308A which was drilling over the year end 2012 and the completion of a seismic acquisition programme over Blocks PM307, PM319 and Block SB307/308.

Other tangible fixed assets amounted to MUSD 85.0 (MUSD 49.4) and included amounts relating to the Ikdam FPSO and to other fixed assets. The Ikdam FPSO is currently being upgraded for use on the Bertam field development project in Malaysia.

Financial assets amounted to MUSD 59.2 (MUSD 44.1) and are detailed in Note 8. Other shares and participations amounted to MUSD 22.0 (MUSD 20.0) and mainly related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income. Deferred tax assets amounted to MUSD 22.4 (MUSD 13.3) and are mainly related to the part of the tax loss carry forwards in the Netherlands that are expected to be utilised against future tax liabilities. The increase compared to the comparative period in deferred tax assets relates mainly to the recognition of previously unrecognised Dutch fiscal unit tax losses following the approval of the field development for the Bertam field, Malaysia, in the fourth quarter of 2013.

Current assets

Receivables and inventories amounted to MUSD 285.7 (MUSD 238.4) and are detailed in Note 9.

Inventories amounted to MUSD 22.8 (MUSD 18.7) and included both hydrocarbon inventories and well supplies. Trade receivables amounted to MUSD 128.9 (MUSD 125.9) and included MUSD 102.5 (MUSD 100.6) relating to Norway. All trade receivables are current. The underlift position amounted to MUSD 9.4 (MUSD 26.4) of which MUSD 6.3 (MUSD 24.6) related to the Gaupe field, Norway. Corporate tax amounted to MUSD 6.5 (MUSD 4.0) and included a tax refund due in France of MUSD 5.8 (MUSD 3.5). Joint venture debtors amounted to MUSD 25.2 (MUSD 11.5) and increased compared to the prior year end position due to the higher level of activity. Derivative instruments amounted to MUSD 3.2 (MUSD 9.1) and related to the mark-to-market on part of the outstanding foreign currency hedge contracts, see also the Derivative financial instruments section below. Prepaid expenses and accrued income amounted to MUSD 62.1 (MUSD 32.9) and represented prepaid operational and insurance expenditure including mobilisation costs of a Norwegian rig to be charged out to future wells. Other current assets amounted to MUSD 27.6 (MUSD 9.9) and included amounts receivable on farm-outs in Norway and Indonesia and VAT and other miscellaneous receivables

Cash and cash equivalents amounted to MUSD 92.7 (MUSD 97.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Provisions amounted to MUSD 1,351.2 (MUSD 1,204.6) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 246.1 (MUSD 190.5) and related to future decommissioning obligations. The provision has increased during the reporting period following the inclusion of the Brynhild field totalling MUSD 24.4, updated cost estimates for the other fields and the unwinding of the discounting of the site restoration provision. The provision for deferred taxes amounted to MUSD 1,067.6 (MUSD 942.2) of which MUSD 924.6 (MUSD 802.8) related to Norway. The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction. The non-current portion of the provision for Lundin Petroleum's LTIP scheme amounted to MUSD 30.8 (MUSD 67.1). Lundin Petroleum's LTIP scheme is outlined in this report under the Remuneration section. The phantom option plan vests in May 2014 at which time 50 percent of the vested amount will become payable and this amount due is included in provisions in current liabilities, see also the Related party transactions section below. The non-current portion of the provision includes the vested amount of the phantom option plan which is payable in May 2015. Derivative instruments amounted to MUSD 1.6 (MUSD -) and related to the mark-to-market on part of the outstanding foreign currency hedge and interest rate contracts to be settled after twelve months.

Financial liabilities amounted to MUSD 1,239.1 (MUSD 384.2). Bank loans amounted to MUSD 1,275.0 (MUSD 432.0) and related to the outstanding loan under the Group's USD 2.5 billion revolving borrowing base facility. Capitalised financing fees amounted to MUSD 35.9 (MUSD 47.8) relating to the establishment costs of the USD 2.5 billion financing facility are being amortised over the expected life of the financing facility.

Other non-current liabilities amounted to MUSD 25.0 (MUSD 22.6) and mainly arise from the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities

Current liabilities amounted to MUSD 446.2 (MUSD 423.4) and are detailed in Note 12.

The overlift position amounted to MUSD 29.2 (MUSD 0.5) and related to the overlift of the Alvheim and Volund fields production entitlement at 31 December 2013. During the second quarter of 2013, Lundin Petroleum entered into a new sales agreement for crude oil production from the Alvheim and Volund fields whereby Lundin Petroleum will receive cash payment based upon forecast production rather than crude oil lifted. As Lundin Petroleum only records sales at the time that a cargo of crude oil is lifted and risk passes to the purchaser, there will be an amount payable or receivable between Lundin Petroleum and the purchaser reflecting the difference between forecast production and actual liftings. As at 31 December 2013, the amount of deferred revenue amounted to MUSD – (MUSD 1.6). Tax liabilities amounted to MUSD 4.7 (MUSD 170.0) of which MUSD 3.6 (MUSD 163.6) related to Norway. Joint venture creditors and accrued expenses amounted to MUSD 334.5 (MUSD 213.9) and MUSD 41.0 (MUSD 8.3) respectively and related mainly to the increased development and drilling activity in Norway. Derivative instruments amounted to MUSD 4.0 (MUSD -) and related to the mark-to-market on part of the outstanding foreign currency hedge and interest rate contracts to be settled within twelve months.

Short term provisions amounted to MUSD 46.2 (MUSD 8.8) and related to the current portion of the provision for Lundin Petroleum's LTIP scheme. The current portion of the provision includes the vested amount of the phantom option plan payable in May 2014, see also the Related party transactions section below.

PARENT COMPANY

The business of the Parent Company is investment in and management of oil and gas assets. The net result for the Parent Company amounted to MSEK 76.1 (MSEK 762.2) for the reporting period.

The result included general and administrative expenses of MSEK 105.7 (MSEK 84.6) and financial income relating to guarantee fees of MSEK 3.1 (MSEK 1.6) and a dividend received from a subsidiary of MSEK 178.2 (MSEK 804.7). Financial expenses related to interest expense from a group company of MSEK 2.3 (MSEK 31.3).

Pledged assets of MSEK 12,014.5 (MSEK 11,911.6) relate to the accounting value of the pledge of the shares in respect of the financing facility entered into by its fully-owned subsidiary Lundin Petroleum BV, see also the Liquidity section below.

RELATED PARTY TRANSACTIONS

During the reporting period, the Group has entered into transactions with related parties on a commercial basis as described below.

The Group received MUSD 0.4 (MUSD 0.4) from ShaMaran Petroleum for the provision of office and other services.

The Group paid MUSD 0.1 (MUSD 0.8) to other related parties in respect of aviation services received.

In the third quarter of 2013, the Group purchased a corporate aircraft from a related party company for MUSD 2.8. The aircraft has been capitalised as part of other fixed assets.

During the fourth quarter of 2013, Lundin Petroleum announced that Mr Turbott, VP Finance and CFO, will leave the Company in mid-2014. Under agreed severance terms, Mr Turbott will receive a payment equal to one years' base salary on his departure, which the Board authorised as a permitted deviation from the Policy on Remuneration for the Executive Management, taking into account the special circumstances of Mr Turbott's substantial contributions to the Company over his years of service. In accordance with the rules of the phantom option plan, Mr Turbott will receive full settlement for his entitlement under the plan in 2014. The Group has also entered into a loan agreement with Mr Turbott for a maximum amount of MUSD 3.0. All amounts plus interest are repayable on or before 30 June 2014.

LIQUIDITY

On 25 June 2012, Lundin Petroleum entered into a seven year senior secured revolving borrowing base facility of USD 2.5 billion with a group of 25 banks to provide funding for Lundin Petroleum's ongoing exploration expenditure and development costs, particularly in Norway. The USD 2.5 billion financing facility is a revolving borrowing base facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 31 December 2013 is MUSD 1,870.3 (MUSD 1,831.3) equivalent and represents the accounting value of net assets of the Group companies whose shares are pledged as described in the parent company section above.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas). Bank guarantees have been issued in support of the work commitments in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 31 December 2013 was MUSD 11.9.

SUBSEQUENT EVENTS

In January 2014, Lundin Petroleum announced that it had been awarded nine exploration licences in the Norwegian APA 2013 licensing round, four of which will be operated by Lundin Petroleum.

In January 2014, Lundin Petroleum announced that it had agreement from its banking syndicate to increase its existing USD 2.5 billion credit facility to USD 4.0 billion on similar terms to the existing facility. The increased facility is subject to final documentation.

Lundin Petroleum announced in January 2014 that the sidetrack exploration well 16/2-20A on the Torvastad prospect on PL501 (WI 40%) was in the process of being completed. The well appears uncommercial and the associated costs of the original well and the sidetrack will likely be expensed in the first quarter of 2014.

SHARE DATA

Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 317,910,580 shares with a quota value of SEK 0.01 each. Lundin Petroleum holds 8,340,250 of its own shares.

The Board of directors will propose to the AGM that no dividend will be paid to the shareholders for the financial year 2013.

REMUNERATION

Lundin Petroleum's principles for remuneration and details of the Unit Bonus and Phantom Option Plans are provided in the Company's 2012 Annual Report.

Unit Bonus Plan

The number of units relating to the 2011, 2012 and 2013 Unit Bonus Plans outstanding as at 31 December 2013 were 123,992, 238,496 and 422,730 respectively.

Phantom Option Plan

The LTIP for Executive Management includes 5,500,928 phantom options with an exercise price of SEK 52.91. The phantom options will vest in May 2014 being the fifth anniversary of the date of grant.

Lundin Petroleum holds 8,340,250 of its own shares which mitigates against the exposure of the LTIP. The Lundin Petroleum share price at 31 December 2013 was SEK 125.40. The provision for the Phantom Option Plan amounted to MUSD 68.2 including social charges as at 31 December 2013 and the market value of the shares held at 31 December 2013 was MUSD 162.8. The gain in the value of the own shares held cannot be offset against the cost for the LTIP in the financial statements in accordance with accounting rules. For more detail on the accounting treatment refer to the section on non-current liabilities above.

ACCOUNTING POLICIES

This interim report has been prepared in accordance with International Accounting Standard (IAS) 34, Interim Financial Reporting, and the Swedish Annual Accounts Act (SFS 1995:1554). As from 1 January 2013, Lundin Petroleum has applied the following new accounting standards: IFRS 13 Fair value measurement, revised IAS 1 Presentation of financial statements and amendment to IFRS 7 Financial instruments. The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2012 except for the classification of the change in under/over lift position as mentioned below.

With effect from 1 January 2013, the change in under/over lift position is reported in revenue and not as previously reported in production costs as detailed in Note 1. The comparative amounts have been restated. Under or overlifted positions of hydrocarbons are valued at market prices prevailing at the balance sheet date. An underlift of production from a field is included in the current receivables and valued at the balance sheet date spot price or prevailing contract price and an overlift of production from a field is included in the current liabilities and valued at the balance sheet date spot price or prevailing contract price. A change in the under/over lift position is reflected in the income statement as revenue such that revenue reflects the Group's working interest share of production (entitlement method).

The financial reporting of the Parent Company has been prepared in accordance with accounting principles generally accepted in Sweden, applying RFR 2 Reporting for legal entities, issued by the Swedish Financial Reporting Board and the Annual Accounts Act (SFS 1995:1554).

Under Swedish company regulations it is not allowed to report the Parent Company results in any other currency than SEK or Euro and consequently the Parent Company's financial information is reported in SEK and not the Group's reporting currency of USD.

RISKS AND RISK MANAGEMENT

The objective of Business Risk Management is to identify, understand and manage threats and opportunities within the business on a continual basis. This objective is achieved by creating a mandate and commitment to risk management at all levels of the business. This approach actively addresses risk as an integral and continual part of decision making within the Group and is designed to ensure that all risks are identified, fully acknowledged, understood and communicated well in advance. The ability to manage and or mitigate these risks represents a key component in ensuring that the business aim of the Company is achieved. Nevertheless, oil and gas exploration, development and production involve high operational and financial risks, which even a combination of experience, knowledge and careful evaluation may not be able to fully eliminate or which are beyond the Company's control.

A detailed analysis of Lundin Petroleum's strategic, operational, financial and external risks and mitigation of those risks through risk management is described in Lundin Petroleum's 2012 Annual Report.

Derivative financial instruments
Lundin Petroleum entered into the following currency hedging contracts to meet part of the 2013 and future NOK operational requirements as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 1,537.6	MUSD 256.1	NOK 6.00: USD 1	2 Jan 2013 – 20 Dec 2013
MNOK 2,162.1	MUSD 353.9	NOK 6.11: USD 1	21 Jan 2014 – 28 Dec 2014
MNOK 1,200.6	MUSD 191.9	NOK 6.26: USD 1	21 Jan 2015 – 21 Dec 2015

In the first quarter of 2013, the Group also entered into a three year fixed interest rate swap, starting 1 April 2013, in respect of MUSD 500 of borrowings, fixing the floating LIBOR rate at approximately 0.57 percent per annum for the duration of the hedge.

Under IAS 39, subject to hedge effectiveness testing, all of the hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. At 31 December 2013, a current asset amounting to MUSD 3.2 (MUSD 9.1) and a non-current asset of MUSD 3.0 (MUSD –) has been recognised representing the fair value of part of the currency hedging contracts. The comparative period short term current asset related to currency hedge contracts. In addition, a current liability of MUSD 4.0 (MUSD –) and a non-current liability of MUSD 1.6 (MUSD –) has been recognised representing the fair value of the outstanding currency and interest rate hedges.

EXCHANGE RATES
For the preparation of the financial statements for the reporting period, the following currency exchange rates have been used.

	31 Dec 2013		31 Dec 2012	
	Average	Period end	Average	Period end
1 USD equals NOK	5.8753	6.0837	5.8148	5.5639
1 USD equals Euro	0.7529	0.7251	0.7778	0.7579
1 USD equals Rouble	31.8675	32.8653	31.0546	30.5665
1 USD equals SEK	6.5132	6.4238	6.7725	6.5045

CONSOLIDATED INCOME STATEMENT IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013-31 Dec 2013 12 months**	**1 Oct 2013-31 Dec 2013 3 months**	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months
Revenue[1]	1	**1,195.8**	**288.2**	1,375.8	346.9
Cost of sales					
Production costs[1]	2	-195.8	-58.6	-203.2	-52.6
Depletion and decommissioning costs		-174.2	-52.1	-191.4	-50.0
Exploration costs		-287.8	-135.0	-168.4	-134.9
Impairment costs of oil and gas properties		-123.4	–	-237.5	-237.5
Gross profit	3	**414.6**	**42.5**	575.3	-128.1
General, administration and depreciation expenses		-43.6	-12.1	-31.8	-5.4
Operating profit		**371.0**	**30.4**	543.5	-133.5
Result from financial investments					
Financial income	4	3.3	0.9	27.3	10.5
Financial expenses	5	-86.3	-22.7	-48.5	-10.3
		-83.0	**-21.8**	-21.2	0.2
Profit before tax		**288.0**	**8.6**	522.3	-133.3
Income tax expense	6	-215.1	14.4	-418.4	80.6
Net result		**72.9**	**23.0**	103.9	-52.7
Net result attributable to the shareholders of the Parent Company:		77.6	23.7	108.2	-51.5
Net result attributable to non-controlling interest:		-4.7	-0.7	-4.3	-1.2
Net result		**72.9**	**23.0**	103.9	-52.7
Earnings per share – USD[2]		0.25	0.08	0.35	0.21

[1] The comparatives have been restated for the reclassification of the change in under/over lift from production cost to revenue from 1 January 2013.
[2] Based on net result attributable to shareholders of the Parent Company.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME IN SUMMARY

Expressed in MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Net result	72.9	23.0	103.9	-52.7
Other comprehensive income				
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	-31.7	2.6	61.6	25.4
Cash flow hedges	-8.1	5.2	9.2	-4.8
Available-for-sale financial assets	1.9	2.8	16.1	-2.9
Income tax relating to other comprehensive income	1.9	-1.4	-2.3	1.2
Other comprehensive income, net of tax	-36.0	9.2	84.6	18.9
Total comprehensive income	36.9	32.2	188.5	-33.8
Total comprehensive income attributable to:				
Shareholders of the Parent Company	44.7	33.4	190.2	-33.4
Non-controlling interest	-7.8	-1.2	-1.7	-0.4
	36.9	32.2	188.5	-33.8

CONSOLIDATED BALANCE SHEET IN SUMMARY

Expressed in MUSD	Note	**31 December 2013**	31 December 2012
ASSETS			
Non-current assets			
Oil and gas properties	7	3,851.9	2,864.4
Other tangible fixed assets		85.0	49.4
Financial assets	8	59.2	44.1
Total non-current assets		**3,996.1**	2,957.9
Current assets			
Receivables and inventories	9	285.7	238.4
Cash and cash equivalents		92.7	97.4
Total current assets		**378.4**	335.8
TOTAL ASSETS		**4,374.5**	3,293.7
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,207.0	1,182.4
Non-controlling interest		59.8	67.7
Total equity		**1,266.8**	1,250.1
Non-current liabilities			
Provisions	10	1,351.2	1,204.6
Financial liabilities	11	1,239.1	384.2
Other non-current liabilities		25.0	22.6
Total non-current liabilities		**2,615.3**	1,611.4
Current liabilities			
Current liabilities	12	446.2	423.4
Provisions	10	46.2	8.8
Total current liabilities		**492.4**	432.2
TOTAL EQUITY AND LIABILITIES		**4,374.5**	3,293.7

CONSOLIDATED STATEMENT OF CASH FLOW IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013-31 Dec 2013 12 months**	**1 Oct 2013-31 Dec 2013 3 months**	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months
Cash flow from operations					
Net result		72.9	23.0	103.9	-52.7
Adjustments for non-cash related items	14	885.3	192.8	1,056.9	350.6
Gain on sale of asset		–	–	-1.1	-1.1
Interest received		0.9	0.1	3.5	2.2
Interest paid		-21.8	-8.0	-8.9	-3.3
Income taxes paid		-187.7	-13.5	-428.8	-121.6
Changes in working capital		164.6	-58.6	93.5	23.7
Total cash flow from operations		**914.2**	**135.8**	819.0	197.8
Cash flow from investments					
Investment in oil and gas properties		-1,702.0	-492.7	-919.4	-352.2
Investment in office equipment and other assets		-36.2	-16.5	-9.7	-4.9
Investment in subsidiaries		-3.5	–	-10.2	–
Decommissioning costs paid		-1.5	-0.8	-18.6	-9.9
Other payments		-0.4	–	-3.2	-0.3
Total cash flow from investments		**-1,743.6**	**-510.0**	-961.1	-367.3
Cash flow from financing					
Changes in long-term liabilities		845.1	370.4	225.7	111.2
Financing fees paid		–	–	-49.2	-0.4
Purchase of own shares		-20.1	–	-8.7	–
Distributions		-0.1	–	–	–
Total cash flow from financing		**824.9**	**370.4**	167.8	110.8
Change in cash and cash equivalents		-4.5	-3.8	25.7	-58.7
Cash and cash equivalents at the beginning of the period		97.4	97.4	73.6	156.9
Currency exchange difference in cash and cash equivalents		-0.2	-0.9	-1.9	-0.8
Cash and cash equivalents at the end of the period		**92.7**	**92.7**	97.4	97.4

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY IN SUMMARY

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Net result	Non-controlling interest	Total equity
Balance at 1 January 2012	**0.5**	**337.8**	**502.5**	**160.1**	**69.4**	**1,070.3**
Transfer of prior year net result	–	–	160.1	-160.1	–	–
Comprehensive income						
Net result	–	–	–	108.2	-1.7	106.5
Other comprehensive income	–	82.0	–	–	–	82.0
Total comprehensive income	**–**	**82.0**	–	**108.2**	**-1.7**	**188.5**
Transactions with owners						
Purchase of own shares	–	-8.7	–	–	–	-8.7
Total transactions with owners	**–**	**-8.7**	**–**	**–**	**–**	**-8.7**
Balance at 31 December 2012	**0.5**	**411.1**	**662.6**	**108.2**	**67.7**	**1,250.1**
Transfer of prior year net result	–	–	108.2	-108.2	–	–
Comprehensive income						
Net result	–	–	–	77.6	-7.8	69.8
Other comprehensive income	–	-32.9	–	–	–	-32.9
Total comprehensive income	**–**	**-32.9**	–	**77.6**	**-7.8**	**36.9**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-20.1	–	–	–	-20.1
Total transaction with owners	**–**	**-20.1**	**–**	**–**	**-0.1**	**-20.2**
Balance at 31 December 2013	**0.5**	**358.1**	**770.8**	**77.6**	**59.8**	**1,266.8**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Revenue, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Crude oil	1,060.8	249.1	1,169.0	290.1
Condensate	3.4	1.1	3.3	2.6
Gas	160.0	41.1	147.2	44.6
Net sales of oil and gas	**1,224.2**	**291.3**	1,319.5	337.3
Change in under/over lift position	-45.2	-7.2	30.7	4.3
Other revenue	16.8	4.1	25.6	5.3
Revenue	**1,195.8**	**288.2**	1,375.8	346.9

The reclassification of the change in under/over lift from production costs to revenue is effective from 1 January 2013 and the comparatives have been restated.

Note 2. Production costs, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Cost of operations	114.6	32.6	105.6	29.2
Tariff and transportation expenses	25.7	5.8	29.7	8.7
Direct production taxes	44.0	10.0	51.3	12.3
Change in inventory position	-2.0	-1.9	14.8	2.4
Other	13.5	12.1	1.8	–
	195.8	**58.6**	203.2	52.6

The reclassification of the change in under/over lift from production costs to revenue is effective from 1 January 2013 and the comparatives have been restated.

Note 3. Segment information, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Norway				
Crude oil	886.6	209.7	953.4	235.5
Condensate	2.0	0.5	2.3	2.3
Gas	98.5	25.3	94.9	30.6
Net sales of oil and gas	**987.1**	**235.5**	1,050.6	268.4
Change in under/over lift position	-47.0	-9.1	31.4	3.9
Other revenue	5.6	1.5	6.5	1.8
Revenue	**945.7**	**227.9**	1,088.5	274.1
Production costs	-85.1	-32.7	-65.5	-18.9
Depletion and decommissioning costs	-130.2	-41.0	-154.1	-39.6
Exploration costs	-285.4	-134.8	-103.1	-89.4
Impairment costs of oil and gas properties	-81.7	–	-205.8	-205.8
Gross profit	**363.3**	**19.4**	560.0	-79.6
France				
Crude oil	110.2	25.2	115.0	36.7
Net sales of oil and gas	110.2	25.2	115.0	36.7
Change in under/over lift position	-0.4	1.6	–	–
Other revenue	2.2	0.4	2.6	1.5
Revenue	**112.0**	**27.2**	117.6	38.2
Production costs	-34.3	-6.6	-29.9	-12.4
Depletion and decommissioning costs	-12.5	-3.4	-11.7	-3.0
Exploration costs	-0.2	-0.1	-5.0	-4.6
Gross profit	**65.0**	**17.1**	71.0	18.2

Note 3. Segment information cont., MUSD	**1 Jan 2013-31 Dec 2013 12 months**	**1 Oct 2013-31 Dec 2013 3 months**	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months
Netherlands				
Crude oil	0.2	0.1	0.2	0.1
Condensate	1.4	0.6	1.0	0.3
Gas	44.6	11.8	41.4	10.4
Net sales of oil and gas	**46.2**	**12.5**	42.6	10.8
Change in under/over lift position	2.2	0.3	-0.7	-0.2
Other revenue	1.7	0.4	12.2	0.3
Revenue	**50.1**	**13.2**	54.1	10.9
Production costs	-14.7	-4.9	-12.4	-3.8
Depletion and decommissioning costs	-15.0	-3.7	-10.4	-2.4
Exploration costs	-1.3	–	-0.6	-0.1
Gross profit	**19.1**	**4.6**	30.7	4.6
Indonesia				
Gas	16.9	4.0	10.9	3.6
Net sales of oil and gas	**16.9**	**4.0**	10.9	3.6
Change in under/over lift position	–	–	–	0.6
Revenue	**16.9**	**4.0**	10.9	4.2
Production costs	-5.0	-1.2	-5.5	-1.7
Depletion and decommissioning costs	-11.4	-2.7	-5.6	-2.2
Exploration costs	-0.4	-0.1	-7.4	-0.3
Gross profit	**0.1**	**–**	-7.6	–
Russia				
Crude oil	63.8	14.1	75.8	17.8
Net sales of oil and gas	**63.8**	**14.1**	75.8	17.8
Revenue	**63.8**	**14.1**	75.8	17.8
Production costs	-56.3	-12.8	-65.2	-15.4
Depletion and decommissioning costs	-4.9	-1.1	-4.3	-1.0
Impairment costs of oil and gas properties	–	–	-31.7	-31.7
Gross profit	**2.6**	**0.2**	-25.4	-30.3
Other				
Crude oil[1]	–	–	24.6	–
Net sales of oil and gas	–	–	24.6	–
Other revenue	7.3	1.8	4.3	1.7
Revenue	**7.3**	**1.8**	28.9	1.7
Production costs	-0.4	-0.4	-24.7	-0.4
Depletion and decommissioning costs	-0.2	-0.2	-5.3	-1.8
Exploration costs[2]	-0.5	–	-52.3	-40.5
Impairment costs of oil and gas properties[3]	-41.7	–	–	–
Gross profit	**-35.5**	**1.2**	-53.4	-41.0

Within each segment, revenues from transactions with a single external customer amount to ten percent or more of revenue for that segment.

[1] Net sales of crude oil related to Tunisia in the comparative period and in 2012.
[2] Exploration costs in 2012 related mainly to Malaysia and amounted to MUSD 46.7.
[3] Impairment costs of oil and gas properties have been booked in the reporting period relating to Malaysia.

Note 3. Segment information cont., MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Crude oil	1,060.8	249.1	1,169.0	290.1
Condensate	3.4	1.1	3.3	2.6
Gas	160.0	41.1	147.2	44.6
Net sales of oil and gas	**1,224.2**	**291.3**	1,319.5	337.3
Change in under/over lift position	-45.2	-7.2	30.7	4.3
Other revenue	16.8	4.1	25.6	5.3
Revenue	**1,195.8**	**288.2**	1,375.8	346.9
Production costs	-195.8	-58.6	-203.2	-52.6
Depletion and decommissioning costs	-174.2	-52.1	-191.4	-50.0
Exploration costs	-287.8	-135.0	-168.4	-134.9
Impairment costs of oil and gas properties	-123.4	–	-237.5	-237.5
Gross profit	**414.6**	**42.5**	575.3	-128.1

Within each segment, revenues from transactions with a single external customer amount to ten percent or more of revenue for that segment.

Note 4. Financial income, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Interest income	2.3	0.5	5.1	2.6
Foreign currency exchange gain, net	–	–	6.2	5.5
Guarantee fees	0.5	0.2	0.2	0.2
Gain on consolidation of subsidiary	–	–	13.4	–
Other	0.5	0.2	2.4	2.2
	3.3	**0.9**	27.3	10.5

Note 5. Financial expenses, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Interest expense	5.3	1.5	6.8	2.0
Foreign currency exchange loss, net	46.5	13.3	–	–
Result on interest rate hedge settlement	1.5	0.5	0.2	–
Unwinding of site restoration discount	6.1	1.5	5.1	1.3
Amortisation of deferred financing fees	8.7	2.2	6.6	2.0
Loan facility commitment fees	17.1	3.4	10.3	4.7
Impairment of other shares	–	–	18.6	–
Other	1.1	0.3	0.9	0.3
	86.3	**22.7**	48.5	10.3

Note 6. Income tax expense, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Current tax	24.5	24.9	341.3	57.0
Deferred tax	190.6	-39.3	77.1	-137.6
	215.1	**-14.4**	418.4	-80.6

Note 7. Oil and gas properties, MUSD	**31 Dec 2013**	31 Dec 2012
Norway	2,685.6	1,702.3
France	224.4	216.8
Netherlands	60.1	65.8
Indonesia	101.7	96.9
Russia	590.2	599.2
Malaysia	189.9	183.4
	3,851.9	2,864.4

Note 8. Financial assets, MUSD	**31 Dec 2013**	31 Dec 2012
Other shares and participations	22.0	20.0
Deferred tax	22.4	13.3
Bonds	10.4	9.5
Derivative instruments	3.0	–
Other	1.4	1.3
	59.2	44.1

Note 9. Receivables and inventories, MUSD	**31 Dec 2013**	31 Dec 2012
Inventories	22.8	18.7
Trade receivables	128.9	125.9
Underlift	9.4	26.4
Corporate tax	6.5	4.0
Joint venture debtors	25.2	11.5
Derivative instruments	3.2	9.1
Prepaid expenses and accrued income	62.1	32.9
Other	27.6	9.9
	285.7	238.4

Note 10. Provisions, MUSD	**31 Dec 2013**	31 Dec 2012
Non-current:		
Site restoration	246.1	190.5
Deferred tax	1,067.6	942.2
Long-term incentive plan	30.8	67.1
Derivative instruments	1.6	–
Pension	1.5	1.5
Other	3.6	3.3
	1,351.2	1,204.6
Current:		
Long-term incentive plan	46.2	8.8
	46.2	8.8
	1,397.4	1,213.4

Note 11. Financial liabilities, MUSD	**31 Dec 2013**	31 Dec 2012
Bank loans	1,275.0	432.0
Capitalised financing fees	-35.9	-47.8
	1,239.1	384.2

Note 12. Current liabilities, MUSD	**31 Dec 2013**	31 Dec 2012
Trade payables	19.4	15.7
Deferred revenue	–	1.6
Overlift	29.2	0.5
Tax liabilities	4.7	170.0
Accrued expenses	41.0	8.3
Joint venture creditors	334.5	213.9
Derivative instruments	4.0	–
Other	13.4	13.4
	446.2	423.4

Note 13. Financial instruments,
MUSD

For financial instruments measured at fair value in the balance sheet, the following fair value measurement hierarchy is used:

– Level 1: based on quoted prices in active markets;
– Level 2: based on inputs other than quoted prices as within level 1, that are either directly or indirectly observable;
– Level 3: based on inputs which are not based on observable market data.

Based on this hierarchy, financial instruments measured at fair value can be detailed as follows:

31 December 2013 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	21.6	–	0.4
- Bonds	10.4	–	–
- Derivative instruments – non-current	–	3.0	–
- Derivative instruments - current	–	3.2	–
	32.0	6.2	0.4
Liabilities			
- Derivative instruments – non-current	–	1.6	–
- Derivative instruments – current	–	4.0	–
	–	5.6	–

31 December 2012 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	19.6	–	0.4
- Bonds	9.5	–	–
- Derivative instruments – non-current	–	–	–
- Derivative instruments - current	–	9.1	–
	29.1	9.1	0.4
Liabilities			
- Derivative instruments – non-current	–	–	–
- Derivative instruments – current	–	–	–
	–	–	–

There were no transfers between the levels during the reporting period. Other shares and participations and bonds are specified in Note 8 Financial assets.

Derivative instruments are valued using marked-to-market valuations provided by the counterparties to the hedge at the balance sheet date. The hedge counterparties are all banks which are party to the loan facility agreement.

Fair value of the following financial assets and liabilities is estimated to equal the carrying value.
- Trade receivables
- Joint venture debtors
- Cash and cash equivalents
- Trade payables
- Joint venture creditors
- Bank loans
- Other non-current liabilities

The USD 2.5 billion financing facility, entered into on 25 June 2012 is a revolving borrowing base facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The maturity date of the new bank facility is June 2019 and there is a loan reduction schedule which commences in 2016 and reduces to zero by the final maturity date. In addition, the amount available to borrow under the facility is based upon a net present value calculation of the assets' future cash flows. Based on the reduction schedule and the current availability calculation, part of the current outstanding bank loan balance falls due within five years, at the end of 2017.

Note 14. Adjustment for non-cash related items, MUSD	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Exploration costs	287.8	135.0	168.5	134.9
Depletion, depreciation and amortisation	165.3	40.0	189.3	49.1
Current tax	24.5	24.9	341.3	57.0
Deferred tax	190.6	-39.3	77.1	-137.6
Impairment of oil and gas properties	123.4	–	237.5	237.5
Impairment of other shares	–	–	18.6	–
Long-term incentive plan	9.9	0.6	13.0	-1.2
Other[1]	83.8	31.6	11.6	10.9
	885.3	**192.8**	1,056.9	350.6

[1] Other adjustments include foreign exchange differences of MUSD 52.1 (MUSD 5.6) for the reporting period.

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Revenue	**3.1**	**2.2**	71.0	27.0
General and administration expenses	-105.7	-47.6	-84.6	-7.1
Operating profit	**-102.6**	**-45.4**	-13.6	19.9
Result from financial investments				
Financial income	181.4	179.0	807.1	806.1
Financial expenses	-2.7	-1.1	-31.3	-5.5
	178.7	**177.9**	775.8	800.6
Profit before tax	**76.1**	**132.5**	762.2	820.5
Income tax expense	–	–	–	–
Net result	**76.1**	**132.5**	762.2	820.5

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Net result	**76.1**	**132.5**	762.2	820.5
Other comprehensive income	–	–	–	–
Total comprehensive income	**76.1**	**132.5**	762.2	820.5
Total comprehensive income attributable to:				
Shareholders of the Parent Company	76.1	132.5	762.2	820.5
	76.1	**132.5**	762.2	820.5

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in MSEK	**31 December 2013**	31 December 2012
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Receivables from group companies	–	21.4
Other tangible fixed assets	0.2	–
Total non-current assets	**7,872.0**	7,893.2
Current assets		
Receivables	17.3	20.7
Cash and cash equivalents	2.6	1.1
Total current assets	**19.9**	21.8
TOTAL ASSETS	**7,891.9**	7,915.0
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,814.0	7,869.8
Non-current liabilities		
Provisions	36.6	36.4
Payables to group companies	21.6	–
Total non-current liabilities	**58.2**	36.4
Current liabilities		
Current liabilities	19.7	8.8
Total current liabilities	**19.7**	8.8
TOTAL EQUITY AND LIABILITIES	**7,891.9**	7,915.0

Pledged assets	12,014.5	11,911.6

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Cash flow from operations				
Net result	76.1	132.5	762.2	820.5
Adjustment for non-cash related items	-18.9	-19.2	-725.2	-810.7
Changes in working capital	14.2	4.3	-6.4	1.9
Total cash flow from operations	**71.4**	**117.6**	30.6	11.7
Cash flow from investments				
Change in long-term financial fixed assets	–	–	0.1	0.1
Change in other fixed assets	-0.2	-0.2	–	–
Total Cash flow from investments	-0.2	-0.2	0.1	0.1
Cash flow from financing				
Change in long-term liabilities	62.2	-116.3	29.1	-17.7
Purchase of own shares	-131.9	–	-62.4	–
Total cash flow from financing	**-69.7**	**-116.3**	-33.3	-17.7
Change in cash and cash equivalents	1.5	1.1	-2.6	-5.9
Cash and cash equivalents at the beginning of the period	1.1	1.5	3.8	7.0
Currency exchange difference in cash and cash equivalents	–	–	-0.1	–
Cash and cash equivalents at the end of the period	**2.6**	**2.6**	1.1	1.1

PARENT COMPANY STATEMENT OF CHANGES IN EQUITY IN SUMMARY

	Restricted equity		Unrestricted equity			
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Net result	Total equity
Balance at 1 January 2012	**3.2**	**861.3**	**2,551.8**	**3,936.1**	**-182.4**	**7,170.0**
Transfer of prior year net result	–	–	–	-182.4	182.4	–
Total comprehensive income	**–**	**–**	**–**	**–**	**762.2**	**762.2**
Transactions with owners						
Purchase of own shares	–	–	-62.4	–	–	-62.4
Total transactions with owners	**–**	**–**	**-62.4**	**–**	**–**	**-62.4**
Balance at 31 December 2012	**3.2**	**861.3**	**2,489.4**	**3,753.7**	**762.2**	**7,869.8**
Transfer of prior year net result	–	–	–	762.2	-762.2	–
Total comprehensive income	**–**	**–**	**–**	–	**76.1**	**76.1**
Transactions with owners						
Purchase of own shares	–	–	-131.9	**–**	**–**	-131.9
Total transactions with owners	**–**	**–**	**-131.9**	**–**	**–**	**-131.9**
Balance at 31 December 2013	**3.2**	**861.3**	**2,357.5**	**4,515.9**	**76.1**	**7,814.0**

KEY FINANCIAL DATA

Financial data (MUSD)	**1 Jan 2013- 31 Dec 2013 12 months**	**1 Oct 2013- 31 Dec 2013 3 months**	1 Jan 2012- 31 Dec 2012 12 months	1 Oct 2012- 31 Dec 2012 3 months
Revenue[1]	1,195.8	288.2	1,375.8	346.9
EBITDA	960.9	218.6	1,144.1	289.8
Net result	72.9	23.0	103.9	-52.7
Operating cash flow	975.6	204.8	831.4	237.4
Data per share (USD)				
Shareholders' equity per share	3.90	3.90	3.81	3.81
Operating cash flow per share	3.15	0.66	2.68	0.77
Cash flow from operations per share	2.95	0.44	2.64	0.64
Earnings per share	0.25	0.08	0.35	-0.16
Earnings per share fully diluted	0.25	0.08	0.35	-0.16
EBITDA per share	3.10	0.71	3.68	0.93
Dividend per share	–	–	–	–
Number of shares issued at period end	317,910,580	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	309,570,330	309,570,330	310,542,295	310,542,295
Weighted average number of shares for the period	310,017,074	309,570,330	310,735,227	310,542,295
Share price				
Quoted price at period end (SEK)	125.40	125.40	149.50	149.50
Quoted price at period end (CAD)	19.73	19.73	22.87	22.87
Key ratios				
Return on equity (%)	6	2	9	-4
Return on capital employed (%)	16	1	35	-10
Net debt/equity ratio (%)	98	98	28	28
Equity ratio (%)	29	29	38	38
Share of risk capital (%)	53	53	66	66
Interest coverage ratio	51	12	75	-67
Operating cash flow/interest ratio	144	105	119	117
Yield	–	–	–	–

[1] The comparatives have been restated for the reclassification of the change in under/over lift from production cost to revenue from 1 January 2013.

KEY RATIO DEFINITIONS

EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortisation): Operating profit before depletion of oil and gas properties, exploration costs, impairment costs, depreciation of other tangible assets and gain on sale of assets.

Operating cash flow: Revenue less production costs and less current taxes.

Shareholders' equity per share: Shareholders' equity divided by the number of shares in circulation at period end.

Operating cash flow per share: Revenue less production costs and less current taxes divided by the weighted average number of shares for the period.

Cash flow from operations per share: Cash flow from operations in accordance with the consolidated statement of cash flow divided by the weighted average number of shares for the period.

Earnings per share: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period.

Earnings per share fully diluted: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period after considering the dilution effect.

EBITDA per share: EBITDA divided by the weighted average number of shares for the period.

Weighted average number of shares for the period: The number of shares at the beginning of the period with changes in the number of shares weighted for the proportion of the period they are in issue.

Return on equity: Net result divided by average total equity.

Return on capital employed: Income before tax plus interest expenses plus/less exchange differences on financial loans divided by the average capital employed (the average balance sheet total less non-interest bearing liabilities).

Net debt / equity ratio: Bank loan less cash and cash equivalents divided by shareholders' equity.

Equity ratio: Total equity divided by the balance sheet total.

Share of risk capital: The sum of the total equity and the deferred tax provision divided by the balance sheet total.

Interest coverage ratio: Result after financial items plus interest expenses plus/less exchange differences on financial loans divided by interest expenses.

Operating cash flow / interest ratio: Revenue less production costs and less current taxes divided by the interest charge for the period.

Yield: dividend per share in relation to quoted share price at the end of the financial period.

Stockholm, 5 February 2014

Ian H. Lundin Chairman	C. Ashley Heppenstall President and CEO	William A. Rand
Asbjørn Larsen	Lukas H. Lundin	Magnus Unger
Cecilia Vieweg	Peggy Bruzelius	

Financial information

The Company will publish the following reports:

- The three month report (January – March 2014) will be published on 7 May 2014.
- The six month report (January – June 2014) will be published on 6 August 2014.
- The nine month report (January – September 2014) will be published on 5 November 2014.

The AGM will be held on 15 May 2014 in Stockholm, Sweden.

For further information, please contact:

Teitur Poulsen
VP Corporate Planning & Investor Relations
Tel: + 41 22 595 10 00

Maria Hamilton
Head of Corporate Communications
maria.hamilton@lundin.ch
Tel: +46 8 440 54 50
Tel: +41 79 63 53 641

Forward-Looking Statements
Certain statements made and information contained herein constitute "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Company's future performance, business prospects or opportunities. Forward-looking statements include, but are not limited to, statements with respect to estimates of reserves and/or resources, future production levels, future capital expenditures and their allocation to exploration and development activities, future drilling and other exploration and development activities. Ultimate recovery of reserves or resources are based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management.

All statements other than statements of historical fact may be forward-looking statements. Statements concerning proven and probable reserves and resource estimates may also be deemed to constitute forward-looking statements and reflect conclusions that are based on certain assumptions that the reserves and resources can be economically exploited. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations and assumptions will prove to be correct and such forward-looking statements should not be relied upon. These statements speak only as on the date of the information and the Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws. These forward-looking statements involve risks and uncertainties relating to, among other things, operational risks (including exploration and development risks), productions costs, availability of drilling equipment, reliance on key personnel, reserve estimates, health, safety and environmental issues, legal risks and regulatory changes, competition, geopolitical risk, and financial risks. These risks and uncertainties are described in more detail under the heading “Risks and Risk Management” and elsewhere in the Company’s annual report. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. Actual results may differ materially from those expressed or implied by such forward-looking statements. Forward-looking statements are expressly qualified by this cautionary statement.

Reserves and Resources
Unless otherwise stated, Lundin Petroleum’s reserve and resource estimates are as at 31 December 2013, and have been prepared and audited in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Unless otherwise stated, all reserves estimates contained herein are the aggregate of “Proved Reserves” and “Probable Reserves”, together also known as “2P Reserves”. For further information on reserve and resource classifications, see “Reserves, Resources and Production” in the Company’s annual report.

Contingent Resources
Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. There is no certainty that it will be commercially viable for the Company to produce any portion of the Contingent Resources.

Prospective Resources
Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both a chance of discovery and a chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources. Unless otherwise stated, all Prospective Resource estimates contained herein are reflecting a P50 Prospective Resource estimate. Risked Prospective Resources reported herein are partially risked. They have been risked for chance of discovery, but have not been risked for chance of development.

BOEs
BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.