LUNDIN PETROLEUM – PRESS RELEASE

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

Stockholm 6 November 2013

REPORT FOR THE NINE MONTHS ENDED 30 SEPTEMBER 2013

HIGHLIGHTS

Third quarter ended 30 September 2013 (30 September 2012)

- Production of 29.4 Mboepd (36.6 Mboepd) - Reduced production due to the planned Alvheim FPSO shutdown in August and integrity issues on certain Alvheim wells.
- Revenue of MUSD 279.8 (MUSD 343.3)
- EBITDA of MUSD 222.1 (MUSD 273.6)
- Operating cash flow of MUSD 267.9 (MUSD 218.4)
- Net result of MUSD 1.7 (MUSD 44.9)
- Non-cash impairment costs in Malaysia amounted to MUSD 39.3 after tax
- 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

Nine months ended 30 September 2013 (30 September 2012)

- Production of 33.3 Mboepd (35.6 Mboepd)
- Revenue of MUSD 907.6 (MUSD 1,028.9)
- EBITDA of MUSD 742.3 (MUSD 854.3)
- Operating cash flow of MUSD 770.8 (MUSD 594.0)
- Net result of MUSD 49.9 (MUSD 156.6)
- Net debt of MUSD 808 (31 Dec 2012 MUSD 335)
- Oil discovery in Luno II, offshore Norway

	1 Jan 2013- 30 Sep 2013 9 months	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Production in Mboepd	33.3	29.4	35.6	36.6	35.7
Revenue in MUSD	907.6	279.8	1,028.9	343.3	1,375.8
Net result in MUSD	49.9	1.7	156.6	44.9	103.9
Net result attributable to shareholders of the Parent Company in MUSD	53.9	3.0	159.7	45.9	108.2
Earnings/share in USD[1]	0.17	0.01	0.51	0.15	0.35
EBITDA in MUSD	742.3	222.1	854.3	273.6	1,144.1
Operating cash flow in MUSD	770.8	267.9	594.0	218.4	831.4

[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 202 million barrels of oil equivalent (MMboe).

LETTER TO SHAREHOLDERS

Dear fellow Shareholders,
At Lundin Petroleum we believe that the best way to create shareholder value in the upstream oil and gas business is by gaining access to new resources. Over the last ten years we have been very successful in increasing our net resources through an exploration driven organic growth strategy. Today our net resources have grown to over one billion barrels of recoverable oil equivalent with a particular focus on Norway. I am very pleased to report that this strategy continues to deliver positive results with this year's exploration successes at Luno II and Gohta in the Norwegian North and Barents Seas respectively. The emergence of the Norwegian Barents Sea as an oil producing region is of particular importance for our industry, for Norway and Lundin Petroleum.

Strong Financial Position
We have a strong balance sheet at Lundin Petroleum which provides us with a high level of financial flexibility in respect of our ongoing development, appraisal and exploration activities. The cornerstone of our finances is the strong operating cash flow which generated USD 770 million during the first nine months of 2013. This cash flow is being reinvested into the Company and along with the use of bank facilities, funds the costs of our development projects in Norway and South East Asia which will double our production to over 70,000 boepd by the end of 2015. Our main priority however, is to continue our exploration programmes focused in Norway and South East Asia, and in this respect we will likely seek to increase our appraisal and exploration budgets in these areas in 2014 where we have a pipeline of interesting opportunities.

Development projects to double our existing production
We remain firmly on target to double our production to over 70,000 boepd by the end of 2015. My confidence in achieving this target has increased over recent weeks as a result of the excellent progress on the Edvard Grieg development project offshore Norway where we remain on schedule and within budget. The construction of the jacket at Kværner Verdal is well advanced and on schedule for installation in the summer of 2014 and the topsides construction is also underway with most of the procurement process behind us.

We were also pleased to have recently received the Petronas approval for the Bertam development project offshore Malaysia. This is our first project in South East Asia and will add an incremental 10,000 boepd to our production when this field comes onstream in 2015. We are particularly pleased that the Bertam development project will utilise our 100 percent owned Ikdam FPSO which we have redeployed to Malaysia following the abandonment of the Oudna field, offshore Tunisia. The Ikdam FPSO is currently in Singapore undergoing life extension works to enable her to be utilised on the Bertam field.

Unfortunately first oil from the Brynhild development project in Norway will be delayed until 2014. The subsea installation work has been successfully completed on schedule and within budget. Our first development well has now reached final target depth and will be ready for hook up by the end of November and I'm very pleased to report that we have found the Brynhild reservoir as expected. However we have faced delays with the modification of the Haewene Brim FPSO owned by Bluewater and leased to Shell as a production facility for its Pierce field in the United Kingdom. The FPSO modification works to receive Brynhild production and to extend the field life of Pierce have now been completed but are about two months behind schedule. The delays have now taken us into the winter weather window and we are therefore exposed to an increased weather downtime risk in respect of the offshore installation work needed to install the new Pierce/Brynhild production riser. As a result we expect the most likely first oil date from Brynhild to be in the second quarter of 2014.

Our 2013 production year to date is substantially in line with forecast other than the impact of certain integrity issues on three Alvheim wells. However with Brynhild now forecast to come onstream in 2014 there will be no production contribution from Brynhild in 2013 and as a result our 2013 production forecast is now expected at the bottom of our previously guided 33,000 to 38,000 boepd range. Production will increase to over 40,000 boepd when Brynhild commences production in 2014.

Aggressive appraisal programme in 2014
Appraisal of Johan Sverdrup is substantially complete and the conceptual development selection is expected before the end of 2013. Since Lundin Petroleum discovered the Johan Sverdrup field, offshore Norway in 2010 we have together with Statoil drilled 19 appraisal wells on the structure, of which six were sidetracked. The discovery is unquestionably world class and will be one of the five largest fields ever developed on the Norwegian Continental Shelf. Statoil as working operator for the pre development works have now substantially completed the subsurface models and we expect an updated resource estimate to be announced by the end of the year in conjunction with the conceptual development selection. Discussions are currently ongoing between the field partners in reviewing the various concept alternatives. As we have previously indicated this field is most likely to produce in excess of 500,000 boepd when it reaches plateau production and will at that time probably represent over a quarter of Norway's oil production. The discovery has been transformational in respect of the value creation for Lundin Petroleum shareholders. I am convinced that this valuation will increase even further as the size and quality of this exceptional asset gets closer to first production. Our net share of production from Johan Sverdrup will enable us to increase production to over 150,000 boepd - a fourfold increase from today's level.

2014 will see an aggressive appraisal programme on recent exploration discoveries. Our 2014 drilling programme will include the appraisal of the Luno II, Gohta and Tembakau discoveries in Norway and Malaysia.

I believe that this appraisal programme will result in all these three projects achieving commerciality and the consequent booking of reserves.

Expanding exploration programme
We have announced a 2014 exploration drilling programme which shows a continued high level of investment in Norway and Malaysia.

Up to the end of 2014 our exploration drilling programme includes the drilling of at least ten exploration wells in Norway and Malaysia. Today we are the most active exploration company in Norway behind Statoil, and in recent years have certainly been the most successful. This level of activity will continue in 2014 with major exploration drilling programme focusing on our core areas of the Utsira High and Barents Sea as well as a few wells located in new areas. We believe that despite the successes in the Utsira High area with Johan Sverdrup, Edvard Grieg and Luno II the area still has the potential for further success and are particularly excited with the prospects for the ongoing Torvastad well and the Kopervik well to be drilled shortly.

We also believe that the recent oil discoveries in the Barents Sea by Statoil, OMV and ourselves are very important in relation to the future of the Barents Sea as an oil producing region. These recent discoveries proving different play concepts as well as the existence of different active oil source kitchens will in our opinion lead to further discoveries and the development of a production infrastructure in the area. Recent Norwegian licensing rounds have focused almost predominantly on the Barents Sea with a high level of industry interest which will lead to increased activity in the region. Lundin Petroleum has built up a large acreage position in the Barents Sea over the last few years and is well positioned to take advantage of this increased focus. We will be drilling further appraisal and exploration wells in the Barents Sea in 2014.

Exploration drilling will recommence in Malaysia in 2014 with a particular focus on the Sabah area, offshore East Malaysia. We have invested in new 3D acquisition programmes in this region on trend with old Shell oil discoveries and the results have identified some interesting prospectivity which will be drilled next year.

I remain extremely positive regarding the prospects for our Company
We continue to generate strong cash flow, we are well funded with lots of financial flexibility, we are on track to double our production from our development project pipeline by the end of 2015, recent discoveries are being appraised and will result in further reserve increases and Johan Sverdrup is simply a once in a lifetime discovery. Our exploration strategy continues to deliver positive results with our recent discoveries and I am confident this will continue looking at the quality of our 2014 programme.

We are perhaps starting to see light at the end of the tunnel in respect of the world economic situation following the problems in recent years. Growth is starting to reappear albeit slowly in respect of the developed world and it looks likely that Chinese growth rates have bottomed out. This has to be positive for commodity prices including oil. Nevertheless, it is worth noting that oil prices have remained well above USD 100 per barrel despite the recent extraordinary increase in domestic US shale oil production. It is very clear that without this US production increase the fragile political situation in the Middle East would have resulted in a very tight market. I remain positive on the prospects for oil prices in the medium to long term.

We recently announced that our Chief Financial Officer Geoff Turbott will be shortly stepping down from his position. I have worked with Geoff for the last 18 years over which he has been an integral and important part of our management team ensuring that we have been able to access the funding to grow our business and create shareholder value. I would like to thank Geoff for his contribution to our success story and wish him the very best for the future. I would also like to welcome Mike Nicholson to our management team in the role as Chief Financial Officer. Mike has done an excellent job over the last five years growing our South East Asian business and is one of a number of younger executives within our Company who have the capacity to assist us in taking Lundin Petroleum forward for many years to come.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 6 November 2013

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon two core areas, Norway and South East Asia, as well as in France, The Netherlands and Russia. Norway continues to represent the majority of Lundin Petroleum's operational activities with production during the first nine months 2013 accounting for 74 percent of total production and with 75 percent of Lundin Petroleum's total reserves as at the end of 2012.

RESERVES AND RESOURCES

Lundin Petroleum has 201.5 million barrels of oil equivalent (MMboe) of reserves as certified at the end of 2012. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. The Johan Sverdrup field in Norway constitutes more than two thirds of the 923 MMboe[1] of Lundin Petroleum's best estimate contingent resources and will be moved to reserves following the finalisation of a unitisation agreement and the submission of a development plan expected at the end of 2014.

PRODUCTION

Production for the nine month period ended 30 September 2013 (reporting period) amounted to 33.3 thousand barrels of oil equivalent per day (Mboepd) (compared to 35.6 Mboepd over the same period in 2012) and was comprised as follows:

Production in Mboepd	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Crude oil					
Norway	21.1	18.3	23.4	23.4	23.3
France	2.8	3.0	2.9	2.8	2.8
Russia	2.4	2.2	2.7	2.7	2.7
Tunisia	–	–	0.1	–	0.1
Total crude oil production	**26.3**	**23.5**	29.1	28.9	28.9
Gas					
Norway	3.4	2.5	3.8	5.0	3.9
Netherlands	2.0	1.8	1.9	1.9	1.9
Indonesia	1.6	1.6	0.8	0.8	1.0
Total gas production	**7.0**	**5.9**	6.5	7.7	6.8
Total production					
Quantity in Mboe	**9,079.7**	**2,704.3**	9,749.6	3,364.5	13,050.4
Quantity in Mboepd	**33.3**	**29.4**	35.6	36.6	35.7

NORWAY

Production

Production in Mboepd	Working Interest (WI)	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Volund	35%	12.6	11.3	13.3	13.4	13.1
Alvheim	15%	10.5	8.9	11.9	11.4	11.8
Gaupe	40%	1.4	0.6	2.0	3.6	2.3
		24.5	**20.8**	27.2	28.4	27.2

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. The cost of operations, excluding project specific costs, for the Volund field during the reporting period was below USD 2.50 per barrel.

Notwithstanding the planned Alvheim FPSO shut-in during August 2013 the net 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 one of the wells which was shut-in in June 2013. The flowline integrity issue has been

[1] Includes mid point of the guided range for the PL501 part of Johan Sverdrup (range 800 – 1,800 MMboe, gross) and mid point of Statoil's guided range for the PL265 part of Johan Sverdrup (range 900 – 1,500 MMboe, gross) plus Geitungen (range 140 – 270 MMboe, gross).

resolved with the well coming back onstream in September 2013. The remaining two shut-in wells are scheduled to be worked over during the fourth quarter 2013 and brought back onstream in early 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 vessel for the comparative period. The Alvheim FPSO uptime levels for the reporting period of close to 95 percent have had a positive impact on the Alvheim production. The cost of operations for the Alvheim field, excluding well intervention and other one-off related project work, was below USD 5.20 per barrel during the reporting period. The one-off well intervention work during 2013 is being recorded as cost of operations and is forecast to account for USD 1.70 of Lundin Petroleum's total cost of operations per barrel for the full year. A further three infill development wells are scheduled to be drilled on Alvheim in 2014 and 2015. In addition, one exploration well is planned to be drilled north of the main Alvheim field in 2014 targeting the North Kameleon prospect.

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.

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	Late 2014	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 TD and the well 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 Brynhild, 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 has progressed slower than expected with the FPSO vessel to leave the yard in the next few days, approximately two months behind schedule. Once the FPSO returns to the Pierce field location further installation and commissioning work needs to be completed including the installation of a new production riser. This work is dependent upon offshore weather conditions and therefore our best estimate of first oil from the Brynhild field is now 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.

Edvard Grieg
The 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. An appraisal well is planned to be drilled in the southeastern part of the Edvard Grieg reservoir in 2013 with potential to increase reserves and optimise the location of the Edvard Grieg development wells. 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 in October 2013 a PIO was also submitted for 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 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 Edvard Grieg development plan incorporates the provision for the coordinated development solution with the nearby Ivar Aasen field (formerly Draupne) located in PL001B and operated by Det norske oljeselskap ASA. 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. An appraisal programme is ongoing to define the recoverable resource and assist with the development planning strategy.

A total of 19 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, is anticipated to release updated resource estimates for the field towards the end of 2013 in conjunction with a concept development selection.

All parties in PL501 and PL265 have agreed a timetable for the Johan Sverdrup field with a development concept selection to be made by the fourth quarter of 2013, a plan of development to be submitted by the fourth quarter of 2014 and first oil production to commence by the end of 2018.

During the reporting period seven appraisal wells have been completed.

In July 2013, the appraisal well 16/2-17S and the exploration sidetrack 16/2-17B drilled on the eastern and western side respectively of the boundary fault on PL265, were successfully completed. The appraisal well, which was drilled on the Fault Margin location, encountered an 82 metre gross column of oil bearing good quality Jurassic reservoir sequence and confirming the extension of good Jurassic reservoir close to the Fault Margin. The well was production tested from two zones and achieved a flow rate of 1,500 barrels of oil per day (bopd) from the lower sandstone layers with interbedded shales and 5,900 bopd from the upper zone with excellent quality Jurassic sandstones. The exploration sidetrack well 16/2-17B was drilled 800 metres to the west of the main fault and encountered tight basement with no presence of reservoir.

In July 2013, the appraisal well 16/3-6, which is the tenth well drilled on Johan Sverdrup in PL501, was successfully drilled on the eastern flank of the Johan Sverdrup field. The well encountered excellent upper Jurassic Draupne sandstone with a gross reservoir section of 24 metres with 11.5 metres being above the oil water contact (OWC), which was encountered at 1,926 metres below MSL.

The exploration well 16/2-18S, targeting the Cliffhanger North prospect, was completed in August 2013. The well was targeting new volume to the west of the main bounding fault for Johan Sverdrup field on PL265 but failed to encounter the targeted Jurassic reservoir. A 15 metre oil zone was encountered in weathered and fractured granitic basement with poor production characteristics. The oil is not in communication with the Johan Sverdrup discovery. The well was plugged and abandoned.

In September 2013, the appraisal well 16/5-4 on the extreme southwestern part of Johan Sverdrup in PL501 was successfully completed. The well, which was drilled approximately 3 km from the nearest appraisal well 16/5-3 on PL502, encountered a 6 metre oil-filled reservoir section of excellent quality late Jurassic sands with a high net to gross ratio. The top of the reservoir was encountered 16 metres above the regional oil water contact of 1,922 metres below the MSL.

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
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
PL501	Lundin Petroleum	40%	16/5-4	August 2013	6m	Successfully completed in September 2013

PL501	Lundin Petroleum	40%	16/3-7	October 2013	Drilling ongoing

The partners on PL501 have agreed to drill one additional appraisal well on Johan Sverdrup in early 2014 on the Crestal high between wells 16/2-6, 16/2-7 and 16/3-4. The Crestal high well will be drilled by the Bredford Dolphin rig. The partners on PL265 have agreed to drill on additional appraisal well on Johan Sverdrup in 2014 to the north of the Geitungen discovery well 16/2-12.

Exploration
Seven exploration wells have been completed in Norway in 2013 and one exploration well is currently drilling offshore Norway.

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
PL501	16/2-20	Q3 2013	Torvastad	40%	Lundin Petroleum	Drilling ongoing
PL544		July 2013	Biotitt	40%	Lundin Petroleum	Dry
PL625		Q4 2013/ Q1 2014	Kopervik	40%	Lundin Petroleum	
Utgard High						
PL330		June 2013	Sverdrup	30%	RWE Dea	Dry
Barents Sea						
PL492		July 2013	Gohta	40%	Lundin Petroleum	Oil and Gas discovery – gross contingent resources 105 – 235 MMboe
PL659		Q4 2013	Langlitinden	20%	Det norske oljeselskap	

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 estimates that the Luno II discovery contains gross contingent resources of 25 to 120 MMboe. Immediately north of the Luno II discovery a separate prospect, Luno II North, has been mapped and is estimated to contain gross prospective resources of 10 to 40 MMboe. The Luno II discovery is likely to extend into PL410 (WI 70%) to the east of the discovery well and this potential extension will be appraised during the fourth quarter of 2013. A second Luno II appraisal well will be drilled on PL359 during the first quarter of 2014. The Luno II North prospect on PL359 is likely to also be drilled during 2014 and will also target the 23 MMboe Fignon Miocene exploration prospect.

In August 2013, the Biotitt exploration well on PL544 (WI 40%) was completed as a dry hole. The well encountered in excess of 100 metres of good quality Jurassic and Triassic reservoir sands but the sands were water bearing.

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 will be drilled on Gohta and one exploration well on the Alta prospect on PL609 in 2014. In addition the Langlitinden prospect, operated by Det norske oljeselskap, on PL659 (WI 20%) located to the south east of the Loppa High in the Barents Sea is expected to spud in December 2013, targeting gross prospective resources of 220 MMboe.

In October 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.

The Torvastad prospect on PL501 on the Utsira High is currently drilling. If Torvastad is successful it could prove to be a northerly extension of the Johan Sverdrup discovery on PL501. The Kopervik prospect in PL625 (WI 40%) in the northern part of the Utsira High will be spudded in late 2013 or early 2014.

Lundin Petroleum plans to drill at least eight exploration wells in Norway before the end of 2014. In addition to the Kopervik, Alta, Langlitinden, Luno II/Fignon and North Kameleon exploration wells further wells will 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%) will be drilled in the Norwegian Sea to the south of the Asgard field and to the southwest of the Draugen field. Also in the second half of 2014 the Vollgrav well on PL631 (Wi 60%) will be drilled in the northern North Sea between the Statfjord and Gullfaks fields.

Licence awards and relinquishments
Licences PL409, PL505 and PL563 are in the process of being relinquished and the associated costs were expensed in the third quarter of 2013.

CONTINENTAL EUROPE

Production

Production in Mboepd	WI	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
France						
- Paris Basin	100%[1]	2.4	2.6	2.4	2.3	2.3
- Aquitaine	50%	0.4	0.4	0.5	0.5	0.5
Netherlands	Various	2.0	1.8	1.9	1.9	1.9
		4.8	**4.8**	4.8	4.7	4.7

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

France
Production from France during the reporting period has been stable 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, offset by a production underperformance from certain Aquitaine Basin fields related to various, non-reservoir related, mechanical failures. The Nettancourt exploration well has been delayed and is now planned to be drilled in 2014.

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

Lundin Petroleum is participating in one exploration well onshore Netherlands in 2013 on the Lambertschaag-2 prospect in the Slootdorp licence (WI 7.23%). Four exploration wells are planned to be drilled during 2014, one onshore on the Leeuwarden licence (WI 7.2325%) and two 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 and appraisal wells 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 one oil field called Bertam and one gas discovery called Tembakau.

A field development plan for the Bertam field on Block PM307 (WI 75%) has been approved by Petronas and development has commenced. 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 Electric Submersible Pumps (ESP's). The FPSO life extension work contract has been placed with Keppels Shipyard and work is ongoing in Singapore. 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 contains gross reserves of 17 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 2014.

Block PM308A (WI 35%) contains the Janglau, Rhu and Ara oil discoveries.

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 has been completed and two prospects, Maligan and Kitabu, within the Emerald 3D area 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 the 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 2013-30 Sep 2013 9 months**	**1 Jul 2013-30 Sep 2013 3 months**	1 Jan 2012-30 Sep 2012 9 months	1 Jul 2012-30 Sep 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Singa	25.9%	1.6	1.6	0.8	0.8	1.0

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 fourth quarter of 2013 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, owned by JDC, has been contracted for the purpose of drilling the well and the sidetrack.

Gurita
Following the completion of the interpretation of the 3D seismic acquisition of 950 km^2 acquired in 2012, the Gloria A prospect has been identified as the targeted prospect for the 2013 exploration well on the Gurita Block (WI 90%). The Gloria A prospect, which is estimated to contain gross 25 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 Gloria A prospect is scheduled to be drilled in 2013 immediately following the completion of the drilling of the Balqis and Boni prospects on the Baronang Production Sharing Contract (PSC).

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
In July 2013, Lundin Petroleum announced that it has 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 northeastern Indonesia.

Licence farm-out
During the reporting period, Lundin Petroleum completed the previously announced farm-out agreements with Nido Petroleum Limited (Nido) whereby Nido has acquired a 10 percent interest in the Baronang, Cakalang and Gurita PSCs in return for paying their pro-rata share of back costs and a disproportionate share of the exploration costs associated with the drilling of the Baronang and Gurita wells. Nido also has an option to increase its participating interest in all three PSCs with up to an additional 10 percent on the same terms. The option expires once the drilling campaign commences.

OTHER AREAS

Russia

Production

Production in Mboepd	WI	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Onshore Komi Republic	50%	2.4	2.2	2.7	2.7	2.7

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. The discovery is deemed to be strategic by the Russian Government, due to its offshore location, under the Foreign Strategic Investment Law (FSIL) and thus requiring a majority Russian state ownership in the Block. 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.

FINANCIAL REVIEW

Result
The net result for the nine month period ended 30 September 2013 amounted to MUSD 49.9 (MUSD 156.6). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 53.9 (MUSD 159.7) representing earnings per share of USD 0.17 (USD 0.51).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 742.3 (MUSD 854.3) representing EBITDA per share of USD 2.39 (USD 2.75). Operating cash flow for the reporting period amounted to MUSD 770.8 (MUSD 594.0) representing operating cash flow per share of USD 2.49 (USD 1.91).

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 907.6 (MUSD 1,028.9) 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 932.9 (MUSD 982.2). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 98.32 (USD 101.21) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 108.46 (USD 112.21) 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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	6,079.7	2,138.2	6,210.7	2,001.7	8,270.1
– Average price per boe	*111.34*	*112.31*	*115.60*	*113.57*	*115.29*
France					
– Quantity in Mboe	797.4	363.9	703.2	211.0	1,041.1
– Average price per boe	*106.60*	*108.67*	*111.22*	*111.62*	*110.44*
Netherlands					
– Quantity in Mboe	1.2	–	1.2	–	1.7
– Average price per boe	*97.34*	–	*99.47*	–	*100.09*
Russia					
– Quantity in Mboe	634.6	196.3	756.2	246.4	981.6
– Average price per boe	*78.26*	*81.27*	*76.70*	*75.75*	*77.23*
Tunisia					
– Quantity in Mboe	–	–	227.5	–	227.5
– Average price per boe	–	–	*108.14*	–	*108.14*
Total crude oil sales					
– Quantity in Mboe	**7,512.9**	**2,698.4**	7,898.8	2,459.1	10,522.0
– Average price per boe	***108.04***	***109.56***	*111.27*	*109.62*	*110.90*
Gas and NGL sales					
Norway					
– Quantity in Mboe	1,047.5	285.7	1,046.4	428.1	1,513.9
– Average price per boe	*71.31*	*68.00*	*61.42*	*60.34*	*64.18*
Netherlands					
– Quantity in Mboe	531.2	167.3	534.8	176.7	704.2
– Average price per boe	*63.34*	*61.30*	*59.32*	*59.61*	*60.18*

Indonesia					
– Quantity in Mboe	396.1	132.2	224.7	62.5	338.1
– Average price per boe	*32.46*	*32.78*	*32.79*	*32.66*	*32.43*
Total gas and NGL sales					
– Quantity in Mboe	**1,974.8**	**585.2**	1,805.9	667.3	2,556.2
– Average price per boe	***61.37***	***58.13***	*57.24*	*57.55*	*59.69*
Total sales					
– Quantity in Mboe	**9,487.7**	**3,283.6**	9,704.7	3,126.4	13,078.2
– Average price per boe	***98.32***	***100.39***	*101.21*	*98.51*	*100.89*

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 108.13 per barrel (USD 109.97 per barrel) with the remaining 53 percent (55 percent) of Russian sales being sold on the domestic market at an average price of USD 51.57 per barrel (USD 49.78 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 38.0 (credit of MUSD 26.4) 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 460 thousand barrels (Mbbl) higher than the production volume during the third quarter of 2013.

Other revenue amounted to MUSD 12.7 (MUSD 20.3) 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 137.2 (MUSD 150.6) 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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cost of operations					
– In MUSD	82.0	23.4	76.4	25.9	105.6
– In USD per boe	*9.03*	*8.67*	*7.83*	*7.69*	*8.09*
Tariff and transportation expenses					
– In MUSD	19.9	6.6	21.0	7.4	29.7
– In USD per boe	*2.18*	*2.39*	*2.15*	*2.19*	*2.27*
Royalty and direct production taxes					
– In MUSD	34.0	10.8	39.0	11.9	51.3
– In USD per boe	*3.74*	*3.98*	*4.00*	*3.55*	*3.93*
Change in inventory position					
– In MUSD	-0.1	2.2	12.4	-1.2	14.8
– In USD per boe	*-0.01*	*0.84*	*1.27*	*-0.36*	*1.13*
Other					
– In MUSD	1.4	–	1.8	0.6	1.8
– In USD per boe	*0.16*	*–*	*0.18*	*0.18*	*0.14*
Total production costs					
– In MUSD	**137.2**	**43.0**	150.6	44.6	203.2
– In USD per boe	***15.10***	***15.88***	*15.43*	*13.25*	*15.56*

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 82.0 (MUSD 76.4) and included costs associated with the intervention work on the water disposal wells shared by the Alvheim and Volund fields, Norway and well intervention work and maintenance projects in the Paris Basin fields, France which were performed during the first six months of 2013.

The cost of operations per barrel for the reporting period was USD 9.03 (USD 7.83) per barrel and USD 8.67 (USD 7.69) per barrel for the third 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 third quarter of 2013 of USD 8.67 per barrel compared to the comparative period was impacted by the lower production volumes following the planned maintenance shutdowns on the Norway producing fields during July and August 2013.

The average cost of operations per barrel forecast for the full year 2013, incorporating the planned workovers of the Kneler wells on the Alvheim field to be performed in the fourth quarter, is USD 10.20 per barrel. Excluding operational projects, the 2013 average cost of operations is forecast to be less than USD 8.00 per barrel.

Royalty and direct production taxes amounted to MUSD 34.0 (MUSD 39.0) 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 23.19 (USD 23.16) 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 54.04 (USD 57.07) per exported barrel for the reporting period.

Change in inventory position amounted to a net credit of MUSD 0.1 in the reporting period compared to a net MUSD 12.4 charge in the comparative period. During the third quarter of 2013, there was a cargo lifting from the Aquitaine fields, France, contributing to the net third quarter charge of MUSD 2.3 to production costs. In 2012, there were liftings of inventory from the Ikdam FPSO on the Oudna field, Tunisia, which was the main reason for the MUSD 12.4 charge for the comparative period.

Depletion and decommissioning costs
Depletion charges amounted to MUSD 122.1 (MUSD 141.4) 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 13.35 per barrel. The lower depletion charge for the third quarter compared to the prior quarters of 2013 is due mainly to the lower production volumes from Norway in the third quarter of 2013.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 152.8 (MUSD 33.6) 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 there is uncertainty regarding their recoverability.

During the third quarter of 2013, exploration costs of MUSD 18.5 were expensed and mainly related to the cost of the Biotitt and Cliffhanger exploration wells in Norway on PL544 and PL265 respectively and costs associated with certain licences that were relinquished in Norway during the third quarter.

During the first six months of 2013, MUSD 134.3 was expensed and mainly related to the cost of unsuccessful 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 -) and are detailed in Note 3. The carrying values of oil and gas properties are continuously assessed to ensure recoverability.

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 -) as the resources were determined to be uneconomic following the completion of recent technical studies. There was a MUSD 2.2 deferred tax release against the non-cash impairment cost of MUSD 41.7.

During the second quarter of 2013, impairment costs of MUSD 81.7 were expensed in the income statement and mainly related to the uncommercial gas discoveries on PL438 Skalle, PL533 Salina and PL088 Peik, Norway.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 31.5 (MUSD 26.4) which included non-cash charges of MUSD 4.7 (MUSD 11.1) in relation to the Group's Long-term

Incentive Plan (LTIP) scheme. The higher general and administrative and depreciation expenses in the third quarter compared to the prior quarters in 2013 is attributable to the non-cash charge in relation to the Group's LTIP scheme.

The non-cash charge to the income statement resulting from the additional 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. The Lundin Petroleum share price decreased by seven percent to SEK 138.60 per share during the reporting period compared to a five percent decrease from SEK 169.20 per share during the comparative period. The share price increased by four percent to SEK 138.60 per share during the third quarter of 2013 resulting in a MUSD 7.9 charge to 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.

The cash charge amounted to MUSD 23.6 (MUSD 12.9) for the reporting period and includes the reallocation of costs previously charged through operations and certain advisory fees including business development activities.

Fixed asset depreciation charges for the reporting period amounted to MUSD 3.2 (MUSD 2.4).

Financial income

Financial income for the reporting period amounted to MUSD 2.4 (MUSD 16.8) and is detailed in Note 4. The comparative period includes a gain on consolidation of a subsidiary of MUSD 13.4.

Financial expenses

Financial expenses for the reporting period amounted to MUSD 63.6 (MUSD 38.1) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 3.8 (MUSD 4.8) and represented the proportion of interest charged to the income statement. An additional amount of interest of MUSD 11.1 (MUSD 1.9) 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 33.2 (MUSD -0.7 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 most of the functional currencies in the Group companies 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 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 expenses. 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 5.6 (MUSD 2.9).

The amortisation of the deferred financing fees amounted to MUSD 6.5 (MUSD 4.6) for the reporting period and related to the expensing of the fees incurred in establishing the USD 2.5 billion financing loan facility, which was signed on 25 June 2012, over the period of usage of the facility.

Loan facility commitment fees for the reporting period amounted to MUSD 13.7 (MUSD 5.6). 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. The loan commitment fees in the third quarter of 2013 amounted to MUSD 4.1 compared to MUSD 4.9 for the third quarter of 2012.

Tax

The overall tax charge for the reporting period amounted to MUSD 229.5 (MUSD 499.0) and is detailed in Note 6.

The current tax credit for the reporting period amounted to MUSD 0.4 (MUSD -284.4 charge) of which a MUSD 16.2 credit (MUSD -262.6 charge) related to Norway. Due to the increased level of development and exploration expenditure in Norway as shown in the Non-current assets section below, there is a current tax credit movement of MUSD 38.8 to the income statement in relation to Norway for the third quarter in 2013. The current tax credit in Norway for the reporting period is mainly offset by the current tax charge relating to the French operations.

The deferred tax charge for the reporting period amounted to MUSD 229.9 (MUSD 214.7) and arises primarily where there is a difference in depletion for tax and accounting purposes. In Norway, there is a deferred tax charge for the reporting period of MUSD 226.8 (MUSD 211.0).

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 82 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 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 -4.0 (MUSD -3.1) 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 3,541.1 (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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway	758.0	379.8	235.9	101.2	369.0
France	5.5	2.2	26.3	5.7	29.2
Netherlands	3.5	1.6	6.8	2.0	8.5
Indonesia	-1.0	–	–	–	-0.4
Russia	1.9	1.1	5.7	1.7	7.5
Malaysia	4.8	4.8	–	–	–
	772.7	**389.5**	274.7	110.6	413.8

An amount of MUSD 758.0 (MUSD 235.9) of development expenditure was incurred in Norway during the reporting period, of which MUSD 721.1 (MUSD 174.7) was invested in the Brynhild and Edvard Grieg field developments.

Exploration and appraisal expenditure in MUSD	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway	389.5	150.7	210.2	99.1	323.2
France	2.1	1.0	4.1	3.1	9.8
Indonesia	7.8	-0.7	13.4	6.7	16.4
Russia	3.7	1.6	1.8	-1.2	3.6
Malaysia	33.2	7.3	60.3	48.7	100.5
Other	0.3	0.1	4.3	2.0	3.8
	436.6	**160.0**	294.1	158.4	457.3

Exploration and appraisal expenditure of MUSD 389.5 (MUSD 210.2) was incurred in Norway during the reporting period, mainly on the appraisal drilling of the Johan Sverdrup field and exploration drilling of the Ogna, Jorvik, Carlsberg and Biotitt prospects, the Gohta discovery well and well 6608/2-1S on PL330 which was completed in October 2013.

During the reporting period MUSD 33.2 (MUSD 60.3) was spent in Malaysia on the Ara well on Block PM308A which was drilling over the year end and the completion of a seismic acquisition programme over Blocks PM307, PM319 and Block SB307/308.

Other tangible fixed assets amounted to MUSD 69.2 (MUSD 49.4) and included an amount of MUSD 47.9 (MUSD 32.5) relating to the Ikdam FPSO vessel and MUSD 21.3 (MUSD 16.9) relating to other fixed assets. The Ikdam FPSO vessel is currently being upgraded for use on the Bertam field development project in Malaysia.

Financial assets amounted to MUSD 60.7 (MUSD 44.1) and are detailed in Note 8. Other shares and participations amounted to MUSD 19.1 (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 14.0 (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. Corporate tax amounted to MUSD 16.2 (MUSD -) and is the 2013 Norwegian corporate tax refund which will be received in December 2014. This is shown as part of financial assets and will be reclassified to current assets at the end of 2013.

Current assets
Receivables and inventories amounted to MUSD 217.9 (MUSD 238.4) and are detailed in Note 9.

Inventories amounted to MUSD 20.2 (MUSD 18.7) and included both hydrocarbon inventories and well supplies. Trade receivables amounted to MUSD 119.8 (MUSD 125.9) and included MUSD 93.1 (MUSD 100.6) relating to Norway. All trade receivables are current. The underlift position amounted to MUSD 8.5 (MUSD 26.4) of which MUSD 7.2 (MUSD 24.6) related to the Gaupe field, Norway. Corporate tax amounted to MUSD 4.8 (MUSD 4.0) and included a tax refund in France of MUSD 4.0 (MUSD 3.5). Joint venture debtors amounted to MUSD 24.4 (MUSD 11.5) and increased compared to the year end position due to the higher level of activity and back costs owed following a farm-in deal on certain Indonesian licences. Derivative instruments amounted to MUSD 0.2 (MUSD 9.1) and related to the mark-to-market on part of the outstanding foreign currency hedge contracts, see Derivative financial instruments section below. Prepaid expenses and accrued income amounted to MUSD 33.4 (MUSD 32.9) and included prepaid operational and insurance expenditure.

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

Non-current liabilities
Provisions amounted to MUSD 1,361.8 (MUSD 1,204.6) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 214.2 (MUSD 190.5) and related to future decommissioning obligations. The provision has increased during the reporting period following the inclusion of the Brynhild field development. The subsurface template and manifold and pipelines were installed during the second quarter of 2013 and drilling of the wells is ongoing. The provision for deferred taxes amounted to MUSD 1,104.6 (MUSD 942.2) of which MUSD 962.9 (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 37.0 (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. The non-current portion of the provision includes the 50 percent of the vested amount 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 866.7 (MUSD 384.2). Bank loans amounted to MUSD 905.0 (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 38.3 (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 24.5 (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 458.5 (MUSD 423.4) and are detailed in Note 12.

The overlift position amounted to MUSD 21.3 (MUSD 0.5) and related to the overlift of the Alvheim and Volund fields production entitlement at 30 September 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 30 September 2013, the amount of deferred revenue amounted to MUSD – (MUSD 1.6). Tax liabilities amounted to MUSD 4.5 (MUSD 170.0) of which MUSD - (MUSD 163.6) related to Norway. Norwegian tax instalments in relation to the taxable year 2012 were paid in the first half of 2013. In respect of the taxable year 2013, a Norwegian tax refund is expected to be received in December 2014. Joint venture creditors amounted to MUSD 378.2 (MUSD 213.9) and related mainly to the development and drilling activity in Norway and the increase reflects the higher level of activity. Derivative instruments amounted to MUSD 2.8 (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 40.2 (MUSD 8.8) and related to the current portion of the provision for Lundin Petroleum's LTIP scheme. The current portion of the provision as at 30 September 2013 includes 50 percent of the vested amount of the phantom option plan which is payable in May 2014.

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 -56.4 (MSEK -58.3) for the reporting period.

The result included general and administrative expenses of MSEK 58.1 (MSEK 77.5), guarantee fees of MSEK 2.3 (MSEK –) and interest income from a group company of MSEK 0.4 (MSEK 25.7 interest expense).

Pledged assets of MSEK 12,259.5 (MSEK 11,911.6) relate to the accounting value of the pledge of the shares in respect of the new 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 0.2 (MUSD 0.3) from ShaMaran Petroleum for the provision of office and other services.

The Group paid MUSD 0.1 (MUSD 0.6) 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.

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 30 September 2013 is MUSD 1,912.4 (MUSD 1,831.3) and represents the accounting value of net assets of the Group companies whose shares are pledged.

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 30 September 2013 was MUSD 12.5. In addition, bank guarantees have been issued to cover work commitments in Indonesia amounting to MUSD 0.9.

SUBSEQUENT EVENTS

In October 2013, Lundin Petroleum announced the result of the non-operated wildcat well 6608/2-1S on PL330, Norway, as a dry hole. The costs associated with this well will be expensed in the fourth quarter of 2013.

In October 2013, Lundin Petroleum announced that, along with its partner Gunvor, it had entered into a Heads of Agreement with Rosneft to jointly sell 51 percent of LLC PetroResurs. Lundin Petroleum currently has a 70 percent shareholding in LLC PetroResurs which is the 100 percent owner of the Lagansky licence containing the Morskaya discovery. The finalisation of a full agreement is expected during 2014. No impairment of the carrying value of the Morskaya asset is anticipated as a result of this transaction.

In October 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. 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 also entered into a loan agreement with Mr Turbott for a maximum amount of MUSD 3.0 equivalent. Any amounts drawn under the loan agreement will be repayable on or before 30 June 2014 and will attract interest at a commercial interest rate.

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.

In July 2013, Lundin Petroleum purchased a further 85,280 shares bringing the total number of own shares held to 8,340,250.

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 30 September 2013 were 124,492, 239,294 and 423,939 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 30 September 2013 was SEK 138.60. The provision for the Phantom Option Plan amounted to MUSD 69.8 including social charges as at 30 September 2013 and the market value of the shares held at 30 September 2013 was MUSD 180.3. 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 and consequently the Parent Company's financial information is reported in SEK and not in 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

During the second quarter of 2012, the Group entered into currency hedging contracts to meet part of the 2013 NOK operational requirements as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 670.7	MUSD 110.4	NOK 6.07: USD 1	2 Jan 2013 – 20 Dec 2013

During the first quarter of 2013, the Group entered into currency hedging contracts as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 505.9	MUSD 86.0	NOK 5.88: USD 1	19 Apr 2013 – 20 Dec 2013
MNOK 616.9	MUSD 103.9	NOK 5.94: USD 1	21 Jan 2014 – 19 Dec 2014
MNOK 139.9	MUSD 23.4	NOK 5.99: USD 1	21 Jan 2015 – 21 Dec 2015

During the second quarter of 2013, the Group entered into currency hedging contracts as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 361.0	MUSD 59.7	NOK 6.04: USD 1	19 Jul 2013 – 19 Dec 2013
MNOK 526.4	MUSD 86.9	NOK 6.06: USD 1	21 Jan 2014 – 28 Dec 2014
MNOK 103.8	MUSD 17.0	NOK 6.11: 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 30 September 2013, a current asset amounting to MUSD 0.2 (MUSD 9.1) 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 2.8 (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.

	30 Sep 2013		30 Sep 2012		31 Dec 2012	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	5.8145	6.0081	5.8613	5.6995	5.8148	5.5639
1 USD equals Euro	0.7592	0.7405	0.7802	0.7734	0.7778	0.7579
1 USD equals Rouble	31.6276	32.4502	31.0502	31.0441	31.0546	30.5665
1 USD equals SEK	6.5138	6.4106	6.8146	6.5350	6.7725	6.5045

CONSOLIDATED INCOME STATEMENT IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Revenue[1]	1	**907.6**	**279.8**	1,028.9	343.3	1,375.8
Cost of sales						
Production costs[1]	2	-137.2	-43.0	-150.6	-44.6	-203.2
Depletion and decommissioning costs		-122.1	-36.5	-141.4	-53.7	-191.4
Exploration costs		-152.8	-18.5	-33.6	-10.6	-168.4
Impairment costs of oil and gas properties		-123.4	-41.7	–	–	-237.5
Gross profit	3	**372.1**	**140.1**	703.4	234.4	575.3
General, administration and depreciation expenses		-31.5	-16.1	-26.4	-25.8	-31.8
Operating profit		**340.6**	**124.0**	677.0	208.5	543.5
Result from financial investments						
Financial income	4	2.4	0.6	16.8	9.1	27.3
Financial expenses	5	-63.6	-26.8	-38.1	-10.0	-48.5
		-61.2	**-26.2**	-21.3	-0.9	-21.2
Profit before tax		**279.4**	**97.8**	655.6	207.6	522.3
Income tax expense	6	-229.5	-96.1	-499.0	-162.7	-418.4
Net result		**49.9**	**1.7**	156.6	44.9	103.9
Net result attributable to the shareholders of the Parent Company:		53.9	3.0	159.7	45.9	108.2
Net result attributable to non-controlling interest:		-4.0	-1.3	-3.1	-1.0	-4.3
Net result		**49.9**	**1.7**	156.6	44.9	103.9
Earnings per share – USD[2]		0.17	0.01	0.51	0.15	0.35

[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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Net result	**49.9**	**1.7**	156.6	44.9	103.9
Other comprehensive income					
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-34.3	23.1	36.2	45.3	61.6
Cash flow hedges	-13.3	3.7	14.0	11.3	9.2
Available-for-sale financial assets	-0.9	1.4	19.0	13.5	16.1
Income tax relating to other comprehensive income	3.3	-1.0	-3.5	-2.8	-2.3
Other comprehensive income, net of tax	-45.2	27.2	65.7	67.4	84.6
Total comprehensive income	**4.7**	**28.9**	222.3	112.3	188.5
Total comprehensive income attributable to:					
Shareholders of the Parent Company	11.3	29.5	223.6	110.7	190.2
Non-controlling interest	-6.6	-0.6	-1.3	1.6	-1.7
	4.7	**28.9**	222.3	112.3	188.5

CONSOLIDATED BALANCE SHEET IN SUMMARY

Expressed in MUSD	Note	**30 September 2013**	31 December 2012
ASSETS			
Non-current assets			
Oil and gas properties	7	3,541.1	2,864.4
Other tangible fixed assets		69.2	49.4
Financial assets	8	60.7	44.1
Total non-current assets		**3,671.0**	2,957.9
Current assets			
Receivables and inventories	9	217.9	238.4
Cash and cash equivalents		97.4	97.4
Total current assets		**315.3**	335.8
TOTAL ASSETS		**3,986.3**	3,293.7
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,173.6	1,182.4
Non-controlling interest		61.0	67.7
Total equity		**1,234.6**	1,250.1
Non-current liabilities			
Provisions	10	1,361.8	1,204.6
Financial liabilities	11	866.7	384.2
Other non-current liabilities		24.5	22.6
Total non-current liabilities		**2,253.0**	1,611.4
Current liabilities			
Current liabilities	12	458.5	423.4
Provisions	10	40.2	8.8
Total current liabilities		**498.7**	432.2
TOTAL EQUITY AND LIABILITIES		**3,986.3**	3,293.7

CONSOLIDATED STATEMENT OF CASH FLOW IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cash flow from operations						
Net result		49.9	1.7	156.6	44.9	103.9
Adjustments for non-cash related items	14	692.5	225.1	706.3	255.9	1,056.9
Gain on sale of asset		–	–	–	–	-1.1
Interest received		0.8	0.2	1.3	0.6	3.5
Interest paid		-13.8	-5.8	-5.6	-2.3	-8.9
Income taxes paid		-174.2	-8.8	-307.2	-53.8	-428.8
Changes in working capital		223.2	147.3	69.8	38.1	93.5
Total cash flow from operations		**778.4**	**359.7**	621.2	283.4	819.0
Cash flow from investments						
Investment in oil and gas properties		-1,209.3	-549.9	-567.2	-268.2	-919.4
Investment in office equipment and other assets		-19.7	-10.4	-4.8	-3.4	-9.7
Investment in subsidiaries		-3.5	-3.5	-10.2	-10.2	-10.2
Decommissioning costs paid		-0.7	0.2	-8.7	-8.7	-18.6
Other payments		-0.4	-0.2	-2.9	-0.4	-3.2
Total cash flow from investments		**-1,233.6**	**-563.8**	-593.8	-290.9	-961.1
Cash flow from financing						
Changes in long-term liabilities		474.7	220.6	114.5	121.6	225.7
Financing fees paid		–	–	-48.8	-48.3	-49.2
Purchase of own shares		-20.1	-1.7	-8.7	–	-8.7
Distributions		-0.1	–	–	–	–
Total cash flow from financing		**454.5**	**218.9**	57.0	73.3	167.8
Change in cash and cash equivalents		-0.7	14.8	84.4	65.8	25.7
Cash and cash equivalents at the beginning of the period		97.4	86.5	73.6	90.6	73.6
Currency exchange difference in cash and cash equivalents		0.7	-3.9	-1.1	0.5	-1.9
Cash and cash equivalents at the end of the period		**97.4**	**97.4**	156.9	156.9	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	–	–
Total comprehensive income	**–**	**63.9**	–	**159.7**	**-1.3**	**222.3**
Transactions with owners						
Purchase of own shares	–	-8.7	–	–	–	-8.7
Balance at 30 September 2012	**0.5**	**393.0**	**662.6**	**159.7**	**68.1**	**1,283.9**
Total comprehensive income	**–**	**18.1**	**–**	**-51.5**	**-0.4**	**-33.8**
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	–	–
Total comprehensive income	**–**	**-42.6**	**–**	**53.9**	**-6.6**	**4.7**
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 30 September 2013	**0.5**	**348.4**	**770.8**	**53.9**	**61.0**	**1,234.6**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Revenue, MUSD	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil	811.7	295.7	878.9	269.6	1,169.0
Condensate	2.3	0.9	0.7	0.2	3.3
Gas	118.9	33.1	102.6	38.1	147.2
Net sales of oil and gas	**932.9**	**329.7**	982.2	307.9	1,319.5
Change in under/over lift position	-38.0	-54.0	26.4	20.9	30.7
Other revenue	12.7	4.1	20.3	14.5	25.6
Revenue	**907.6**	**279.8**	1,028.9	343.3	1,375.8

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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cost of operations	82.0	23.4	76.4	25.9	105.6
Tariff and transportation expenses	19.9	6.6	21.0	7.4	29.7
Direct production taxes	34.0	10.8	39.0	11.9	51.3
Change in inventory position	-0.1	2.2	12.4	-1.3	14.8
Other	1.4	–	1.8	0.7	1.8
	137.2	**43.0**	150.6	44.6	203.2

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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway					
Crude oil	676.9	240.2	717.9	227.3	953.4
Condensate	1.5	0.7	–	–	2.3
Gas	73.2	18.7	64.3	25.9	94.9
Net sales of oil and gas	**751.6**	**259.6**	782.2	253.2	1,050.6
Change in under/over lift position	-37.9	-52.1	27.5	20.8	31.4
Other revenue	4.1	1.2	4.7	1.6	6.5
Revenue	**717.8**	**208.7**	814.4	275.6	1,088.5
Production costs	-52.4	-14.0	-46.6	-19.3	-65.5
Depletion and decommissioning costs	-89.2	-26.0	-114.5	-42.6	-154.1
Exploration costs	-150.6	-17.2	-13.7	-0.7	-103.1
Impairment costs of oil and gas properties	-81.7	–	–	–	-205.8
Gross profit	**343.9**	**151.5**	639.6	213.0	560.0
France					
Crude oil	85.0	39.5	78.3	23.6	115.0
Net sales of oil and gas	85.0	39.5	78.3	23.6	115.0
Change in under/over lift position	-2.0	-1.8	–	0.1	–
Other revenue	1.8	0.7	1.1	0.4	2.6
Revenue	**84.8**	**38.4**	79.4	24.1	117.6
Production costs	-27.7	-10.5	-17.5	-5.0	-29.9
Depletion and decommissioning costs	-9.1	-3.1	-8.7	-2.8	-11.7
Exploration costs	-0.1	–	-0.4	-0.1	-5.0
Gross profit	**47.9**	**24.8**	52.8	16.2	71.0

Note 3. Segment information cont., MUSD	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Netherlands					
Crude oil	0.1	–	0.1	–	0.2
Condensate	0.8	0.2	0.7	0.2	1.0
Gas	32.8	10.0	31.0	10.2	41.4
Net sales of oil and gas	**33.7**	**10.2**	31.8	10.4	42.6
Change in under/over lift position	1.9	-0.1	-0.5	-0.1	-0.7
Other revenue	1.3	0.4	11.9	11.3	12.2
Revenue	**36.9**	**10.5**	43.2	21.6	54.1
Production costs	-9.8	-3.4	-8.6	-2.8	-12.4
Depletion and decommissioning costs	-11.3	-3.3	-8.0	-2.6	-10.4
Exploration costs	-1.3	-1.3	-0.5	–	-0.6
Gross profit	**14.5**	**2.5**	26.1	16.2	30.7
Indonesia					
Gas	12.9	4.4	7.3	2.0	10.9
Net sales of oil and gas	**12.9**	**4.4**	7.3	2.0	10.9
Change in under/over lift position	–	–	-0.6	0.1	–
Revenue	**12.9**	**4.4**	6.7	2.1	10.9
Production costs	-3.8	-1.5	-3.8	-0.9	-5.5
Depletion and decommissioning costs	-8.7	-2.9	-3.4	-1.1	-5.6
Exploration costs	-0.3	-0.1	-7.1	-0.1	-7.4
Gross profit	**0.1**	**-0.1**	-7.6	–	-7.6
Russia					
Crude oil	49.7	16.0	58.0	18.7	75.8
Net sales of oil and gas	**49.7**	**16.0**	58.0	18.7	75.8
Revenue	**49.7**	**16.0**	58.0	18.7	75.8
Production costs	-43.5	-13.6	-49.8	-15.1	-65.2
Depletion and decommissioning costs	-3.8	-1.2	-3.3	-1.1	-4.3
Impairment costs of oil and gas properties	–	–	–	–	-31.7
Gross profit	**2.4**	**1.2**	4.9	2.5	-25.4
Other					
Crude oil[1]	–	–	24.6	–	24.6
Net sales of oil and gas	–	–	24.6	–	24.6
Other revenue	5.5	1.8	2.6	1.2	4.3
Revenue	**5.5**	**1.8**	27.2	1.2	28.9
Production costs	–	–	-24.3	-1.5	-24.7
Depletion and decommissioning costs	–	–	-3.5	-3.5	-5.3
Exploration costs[2]	-0.5	0.1	-11.8	-9.7	-52.3
Impairment costs of oil and gas properties[3]	-41.7	-41.7	–	–	–
Gross profit	**-36.7**	**-39.8**	-12.4	-13.5	-53.4

[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. An amount of MUSD 0.5 (MUSD 0.1) has been expensed in the reporting period relating to Malaysia.
[3] Impairment costs of oil and gas properties have been booked in the reporting period relating to Malaysia.

Total					
Crude oil	811.7	295.7	878.9	269.6	1,169.0
Condensate	2.3	0.9	0.7	0.2	3.3
Gas	118.9	33.1	102.6	38.1	147.2
Net sales of oil and gas	**932.9**	**329.7**	982.2	307.9	1,319.5
Change in under/over lift position	-38.0	-54.0	26.4	20.9	30.7
Other revenue	12.7	4.1	20.3	14.5	25.6
Revenue	**907.6**	**279.8**	1,028.9	343.3	1,375.8
Production costs	-137.2	-43.0	-150.6	-44.6	-203.2
Depletion and decommissioning costs	-122.1	-36.5	-141.4	-53.7	-191.4
Exploration costs	-152.8	-18.5	-33.5	-10.6	-168.4
Impairment costs of oil and gas properties	-123.4	-41.7	–	–	-237.5
Gross profit	**372.1**	**140.1**	703.4	234.4	575.3

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- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Interest income	1.8	0.5	2.5	0.9	5.1
Foreign currency exchange gain, net	–	–	0.7	-5.2	6.2
Guarantee fees	0.3	0.1	–	–	0.2
Gain on consolidation of subsidiary	–	–	13.4	13.4	13.4
Other	0.3	–	0.2	0.1	2.4
	2.4	**0.6**	16.8	9.2	27.3

Note 5. Financial expenses, MUSD	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Interest expense	3.8	1.1	4.8	1.6	6.8
Foreign currency exchange loss, net	33.2	17.1	–	–	–
Result on interest rate hedge settlement	1.0	0.5	0.2	–	0.2
Unwinding of site restoration discount	4.6	1.5	3.8	1.3	5.1
Amortisation of deferred financing fees	6.5	2.1	4.6	2.1	6.6
Loan facility commitment fees	13.7	4.1	5.6	4.9	10.3
Impairment of other shares	–	–	18.6	–	18.6
Other	0.8	0.4	0.5	0.2	0.9
	63.6	**26.8**	38.1	10.1	48.5

Note 6. Income tax expense, MUSD	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Current tax	-0.4	-31.1	284.3	80.3	341.3
Deferred tax	229.9	127.2	214.7	82.4	77.1
	229.5	**96.1**	499.0	162.7	418.4

Note 7. Oil and gas properties, MUSD	**30 Sep 2013**	31 Dec 2012
Norway	2,396.9	1,702.3
France	221.2	216.8
Netherlands	58.2	65.8
Indonesia	94.7	96.9
Russia	591.1	599.2
Malaysia	179.0	183.4
	3,541.1	2,864.4

Note 8. Financial assets, MUSD	**30 Sep 2013**	31 Dec 2012
Other shares and participations	19.1	20.0
Bonds	10.1	9.5
Deferred tax	14.0	13.3
Corporate tax	16.2	–
Other	1.3	1.3
	60.7	44.1

Note 9. Receivables and inventories, MUSD	**30 Sep 2013**	31 Dec 2012
Inventories	20.2	18.7
Trade receivables	119.8	125.9
Underlift	8.5	26.4
Corporate tax	4.8	4.0
Joint venture debtors	24.4	11.5
Derivative instruments	0.2	9.1
Prepaid expenses and accrued income	33.4	32.9
Other	6.6	9.9
	217.9	238.4

Note 10. Provisions, MUSD	**30 Sep 2013**	31 Dec 2012
Non-current:		
Site restoration	214.2	190.5
Deferred tax	1,104.6	942.2
Long-term incentive plan	37.0	67.1
Derivative instruments	1.6	–
Pension	1.5	1.5
Other	2.9	3.3
	1,361.8	1,204.6
Current:		
Long-term incentive plan	40.2	8.8
	40.2	8.8
	1,402.0	1,213.4

Note 11. Financial liabilities, MUSD	**30 Sep 2013**	31 Dec 2012
Bank loans	905.0	432.0
Capitalised financing fees	-38.3	-47.8
	866.7	384.2

Note 12. Current liabilities,

MUSD	**30 Sep 2013**	31 Dec 2012
Trade payables	9.8	15.7
Deferred revenue	–	1.6
Overlift	21.3	0.5
Tax liabilities	4.5	170.0
Accrued expenses	33.7	8.3
Joint venture creditors	378.2	213.9
Derivative instruments	2.8	–
Other	8.2	13.4
	458.5	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:

30 September 2013 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	18.7	–	0.4
- Bonds	10.1	–	–
- Derivative instruments – non-current	–	–	–
- Derivative instruments - current	–	0.2	–
	28.8	0.2	0.4
Liabilities			
- Derivative instruments – non-current	–	1.6	–
- Derivative instruments – current	–	2.8	–
	–	4.4	**–**

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, no repayments of the current outstanding bank loan balance falls due within five years.

Note 14. Adjustment for non-cash related items, MUSD	**1 Jan 2013-30 Sep 2013 9 months**	**1 Jul 2013-30 Sep 2013 3 months**	1 Jan 2012-30 Sep 2012 9 months	1 Jul 2012-30 Sep 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Exploration costs	152.8	18.5	33.6	10.6	168.5
Depletion, depreciation and amortisation	125.3	37.7	140.2	50.9	189.3
Current tax	-0.4	-31.1	284.3	80.3	341.3
Deferred tax	229.9	127.2	214.7	82.4	77.1
Impairment of oil and gas properties	123.4	41.7	–	–	237.5
Impairment of other shares	–	–	18.6	–	18.6
Long-term incentive plan	9.3	8.9	14.2	27.9	13.0
Other	52.2	22.2	0.7	3.7	11.6
	692.5	**225.1**	706.3	255.9	1,056.9

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-30 Sep 2013 9 months**	**1 Jul 2013-30 Sep 2013 3 months**	1 Jan 2012-30 Sep 2012 9 months	1 Jul 2012-30 Sep 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Revenue	**0.9**	**1.0**	44.0	22.7	71.0
General and administration expenses	-58.1	-27.2	-77.5	-82.4	-84.6
Operating profit	**-57.2**	**-26.2**	-33.5	-59.7	-13.6
Result from financial investments					
Financial income	2.4	0.7	1.0	0.3	807.1
Financial expenses	-1.6	-1.5	-25.8	-8.7	-31.3
	0.8	**-0.8**	-24.8	-8.3	775.8
Profit before tax	**-56.4**	**-27.0**	-58.3	-68.0	762.2
Income tax expense	–	–	–	–	–
Net result	**-56.4**	**-27.0**	-58.3	-68.0	762.2

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-30 Sep 2013 9 months**	**1 Jul 2013-30 Sep 2013 3 months**	1 Jan 2012-30 Sep 2012 9 months	1 Jul 2012-30 Sep 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Net result	-56.4	-27.0	-58.3	-68.0	762.2
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**-56.4**	**-27.0**	-58.3	-68.0	762.2
Total comprehensive income attributable to:					
Shareholders of the Parent Company	-56.4	-27.0	-58.3	-68.0	762.2
	-56.4	**-27.0**	-58.3	-68.0	762.2

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in MSEK	**30 September 2013**	31 December 2012
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Receivables from group companies	51.7	21.4
Total non-current assets	**7,923.5**	7,893.2
Current assets		
Receivables	17.8	20.7
Cash and cash equivalents	1.5	1.1
Total current assets	**19.3**	21.8
TOTAL ASSETS	**7,942.8**	7,915.0
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,681.5	7,869.8
Non-current liabilities		
Provisions	36.4	36.4
Payables to group companies	208.9	–
Total non-current liabilities	**245.3**	36.4
Current liabilities		
Current liabilities	16.0	8.8
Total current liabilities	**16.0**	8.8
TOTAL EQUITY AND LIABILITIES	**7,942.8**	7,915.0
Pledged assets	12,259.5	11,911.6

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cash flow from operations					
Net result	-56.4	-27.0	-58.3	-68.0	762.2
Adjustment for non-cash related items	0.3	0.3	85.5	86.1	-725.2
Changes in working capital	9.9	-0.3	-8.4	-4.1	-6.4
Total cash flow from operations	**-46.2**	**-27.0**	18.9	14.0	30.6
Cash flow from investments					
Change in long-term receivables	–	–	–	–	–
Change in long-term financial fixed assets	–	–	–	–	0.1
Total Cash flow from investments	–	–	–	–	0.1
Cash flow from financing					
Change in long-term liabilities	178.5	35.4	46.8	-22.1	29.1
Purchase of own shares	-131.9	-11.4	-62.4	–	-62.4
Total cash flow from financing	**46.6**	**24.0**	-15.6	-22.1	-33.3
Change in cash and cash equivalents	**0.4**	**-3.0**	3.3	-8.1	-2.6
Cash and cash equivalents at the beginning of the period	1.1	4.4	3.8	15.2	3.8
Currency exchange difference in cash and cash equivalents	–	0.1	-0.1	-0.1	-0.1
Cash and cash equivalents at the end of the period	**1.5**	**1.5**	7.0	7.0	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	**–**	**–**	**–**	**–**	**58.3**	**58.3**
Transactions with owners						
Purchase of own shares	–	–	-62.4	–	–	-62.4
Total transactions with owners	**–**	**–**	**-62.4**	**–**	**–**	**-62.4**
Balance at 30 September 2012	**3.2**	**861.3**	**2,489.4**	**3,753.7**	**58.3**	**7,165.9**
Total comprehensive income	**–**	**–**	**–**	**–**	**703.9**	**703.9**
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	**–**	**–**	**–**	–	**-56.4**	**-56.4**
Transactions with owners						
Purchase of own shares	–	–	-131.9	**–**	**–**	-131.9
Total transactions with owners	**–**	**–**	**-131.9**	**–**	**–**	**-131.9**
Balance at 30 September 2013	**3.2**	**861.3**	**2,357.5**	**4,515.9**	**-56.4**	**7,681.5**

KEY FINANCIAL DATA

Financial data (MUSD)	**1 Jan 2013- 30 Sep 2013 9 months**	**1 Jul 2013- 30 Sep 2013 3 months**	1 Jan 2012- 30 Sep 2012 9 months	1 Jul 2012- 30 Sep 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Revenue[1]	907.6	279.8	1,028.9	343.3	1,375.8
EBITDA	742.3	222.1	854.3	273.6	1,144.1
Net result	49.9	1.7	156.6	44.9	103.9
Operating cash flow	770.8	267.9	594.0	218.4	831.4
Data per share (USD)					
Shareholders' equity per share	3.79	3.79	3.91	3.91	3.81
Operating cash flow per share	2.49	0.87	1.91	0.70	2.68
Cash flow from operations per share	2.51	1.16	2.00	0.91	2.64
Earnings per share	0.17	0.01	0.51	0.15	0.35
Earnings per share fully diluted	0.17	0.01	0.51	0.15	0.35
EBITDA per share	2.39	0.71	2.75	0.88	3.68
Dividend per share	–	–	–	–	–
Number of shares issued at period end	317,910,580	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	310,542,295
Weighted average number of shares for the period	310,017,074	309,500,416	310,735,227	310,441,462	310,735,227
Share price					
Quoted price at period end (SEK)	138.60	138.60	160.10	160.10	149.50
Quoted price at period end (CAD)	22.40	22.40	23.50	23.50	22.87
Key ratios					
Return on equity (%)	4	–	13	4	9
Return on capital employed (%)	17	6	45	15	35
Net debt/equity ratio (%)	71	71	15	15	30
Equity ratio (%)	31	31	38	38	38
Share of risk capital (%)	58	58	69	69	66
Interest coverage ratio	66	71	132	134	75
Operating cash flow/interest ratio	160	162	119	136	119
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: Net interest bearing liabilities 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, 6 November 2013

C. Ashley Heppenstall
President and CEO

The financial information relating to the nine months ended 30 September 2013 has not been subject to review by the auditors of the Company.

Financial information

The Company will publish the following reports:

- The year end report (January – December 2013) will be published on 5 February 2014.
- The three month report (January – March 2014) will be published on 7 May 2014.

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

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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 2012, 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.