LUNDIN PETROLEUM – PRESS RELEASE

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Company registration number 556610-8055

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

Stockholm 7 May 2013

REPORT FOR THE THREE MONTHS ENDED 31 MARCH 2013

HIGHLIGHTS

Three months ended 31 March 2013 (31 March 2012)
- Production of 35.6 Mboepd (34.7 Mboepd)
- Revenue of MUSD 327.6 (MUSD 364.6)
- EBITDA of MUSD 276.2 (MUSD 309.2)
- Operating cash flow of MUSD 260.0 (MUSD 166.6)
- Net result of MUSD 47.0 (MUSD 47.2)
- Oil discovery in Luno II, offshore Norway
- Extensive appraisal drilling on the Johan Sverdrup field
- Seven licences awarded in the Norwegian 2012 APA licensing round

	1 Jan 2013- 31 Mar 2013 3 months	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Production in Mboepd	35.6	34.7	35.7
Revenue in MUSD	327.6	364.6	1,375.8
Net result in MUSD	47.0	47.2	103.9
Net result attributable to shareholders of the Parent Company in MUSD	48.2	48.8	108.2
Earnings/share in USD[1]	0.16	0.16	0.35
EBITDA in MUSD	276.2	309.2	1,144.1
Operating cash flow in MUSD	260.0	166.6	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,

Our Company is in strong health and 2013 has begun with even more positive news. The value creation for Lundin Petroleum shareholders over recent years has been achieved primarily by our exploration success in Norway.

We recently announced a further exploration discovery in Norway with the completion of the Luno II well. We have unquestionably been the most successful explorer in Norway over recent years and I am pleased that our exploration programme continues to deliver positive results.

We have a very busy exploration drilling programme for the rest of 2013 and in the years to come and I am confident this will result in further discoveries.

I believe Lundin Petroleum is today characterised by five key investment themes.

1. Strong Production – generates strong operating cash flow

Our production for the first quarter of 2013 was 35,600 boepd. About 75 percent of our current production comes from Norway where the Alvheim and Volund fields have outperformed expectations over recent years and still continue to generate the majority of our production.

Our oil is good quality, the Alvheim and Volund crude sells at a premium to Brent, and our operating costs are about USD 8 per barrel. Cash taxes remain low due primarily to the Norwegian fiscal regime which defers a large percentage of taxes for companies like ours who continue to invest in exploration and development. The end result is that we generated operating cash flow of USD 260 million in the first quarter and I expect us to exceed one billion dollars for this year. We are reinvesting this cash flow to develop new fields and drill exploration wells which we believe will further increase shareholder value.

We maintain our production guidance for 2013 of between 33,000 boepd and 38,000 boepd. Existing projects will double our production by the end of 2015.

2. Development projects will double our current production

Our three development projects namely Brynhild, Bøyla and Edvard Grieg are all progressing satisfactorily. These projects will commence production in 2013, 2014 and 2015 respectively and when the Edvard Grieg project is onstream in the fourth quarter of 2015 we will exit that year at a production rate of 70,000 boepd or double our current production. This will result in a significant increase to our cash flow and profitability. The USD 2.2 billion of future capital costs, net to Lundin Petroleum, to complete the Brynhild and Bøyla projects and to achieve first oil from Edvard Grieg will be funded from operating cash flow and existing bank facilities.

We have the people in place to execute these projects and despite the cost inflation being experienced by our industry these projects remain on budget and schedule.

3. Johan Sverdrup – A transformational discovery for Lundin Petroleum

Lundin Petroleum discovered Johan Sverdrup in the Norwegian North Sea. It was the largest oil discovery in 2010 and one of the largest discoveries ever made in the North Sea. It is a world class asset in respect of size and quality and represents the number one priority for ourselves and our partners in respect of development.

15 wells have now been drilled on the structure and the appraisal is now substantially complete. The appraisal programme has provided us with valuable information in respect of the resource size and the development concept.

Statoil as operator of the predevelopment phase will provide an updated resource range for the Johan Sverdrup discovery later this year when details of the concept selection for the development will be announced. The current forecast remains for Johan Sverdrup first oil by the end of 2018.

4. Exploration – Remains the key Focus

Despite Lundin Petroleum's increased development and production activities over recent years our key focus remains exploration. We firmly believe that in the upstream oil and gas business the major value creation is through access to resources and the best way to do this is through successful exploration.

Our 2013 exploration work programme includes the drilling of 18 exploration wells with a budget of close to USD 500 million. We plan to continue to spend at this level of exploration expenditure in years to come and to maintain a continued geographical focus in Norway and South East Asia.

In Norway our major focus for 2013 is continued exploration in the Utsira High area of the North Sea where we have already made the Edvard Grieg, Johan Sverdrup and Apollo discoveries. The recent Luno II discovery is a further validation of our view that there will be more discoveries in this area. I expect us to appraise the Luno II discovery in 2013 as well as drilling further high potential exploration wells in the area at Kopervik, Torvastad and Biotitt. Lundin Petroleum is the major acreage owner in this area and will therefore likely be the major beneficiary of further discoveries.

In Norway we also maintain our view that the Barents Sea will become a major oil producing region. The discovery of oil at Skrugard and Havis, now renamed Johan Castberg, has confirmed our view that large commercial oil discoveries would be made in the region. Lundin Petroleum is one of the largest acreage owners in the Barents Sea and we continue to increase our licence interests in the area with new awards in last year's APA licensing round. We will drill two exploration wells in 2013 on the Gohta and Langlitinden prospects.

Our view is that Norway remains relatively unexplored and therefore the third part of our Norwegian exploration strategy is to find a new core exploration area. An example of a potential new area is the Utgard High in the northern Norwegian Sea where we will be drilling an exploration well on the Sverdrup prospect in PL330 in the third quarter of this year. As was the case with the Utsira High we have secured a large acreage position in this region so that if the exploration programme yields positive results, the value of our surrounding acreage will be enhanced.

I have over recent months become more excited about our South East Asian portfolio, particularly Malaysia. Our team have done a great job in building a material licence portfolio and the early exploration results have been encouraging. I expect that we will announce the go ahead of the Bertam project later this year with the finalisation of the commercial arrangements. In addition, the Tembakau discovery in PM307 will be appraised but it looks like it will be a commercial gas discovery based upon its size and location to market. I am also very encouraged with the results of the latest 3D seismic acquisition from our acreage offshore Sabah and expect to be able to announce a multi-well exploration drilling programme on this acreage later this year.

5. Liquidity and Financial Flexibility

Our balance sheet remains strong with low debt levels. Last year we completed a new USD 2.5 billion loan facility with a syndicate of international banks. Our strong operating cash flow coupled with the debt availability will be sufficient to fund our ongoing development projects in addition to funding our exploration programme. Whilst the final details and costs of the Johan Sverdrup development are not yet finalised I am confident that the cash flow from our Edvard Grieg project coupled with the continued availability of conservative debt levels will allow us to develop Johan Sverdrup without the need for further equity.

I hope that you share my enthusiasm for the future of Lundin Petroleum. Our success will be determined predominately by our ability to execute our development projects and to continue our exploration success. I am confident we will deliver.

Yours sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 7 May 2013

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon two core areas, Norway and South East Asia, as well as assets in France, Netherlands and Russia. Norway continues to represent the majority of Lundin Petroleum's operational activities with production during 2012 accounting for 76 percent of total 2012 production and with 75 percent of Lundin Petroleum's total reserves as at the end of 2012.

PRODUCTION

Production for the three month period ended 31 March 2013 (reporting period) amounted to 35.6 thousand barrels of oil equivalent per day (Mboepd) (34.7 Mboepd) and was comprised as follows:

Production in Mboepd	**1 Jan 2013 – 31 Mar 2013 3 months**	1 Jan 2012 – 31 Mar 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Crude oil			
Norway	22.6	23.0	23.3
France	2.7	2.9	2.8
Russia	2.5	2.8	2.7
Tunisia	–	0.4	0.1
Total crude oil production	**27.8**	29.1	28.9
Gas			
Norway	4.0	2.5	3.9
Netherlands	2.2	2.0	1.9
Indonesia	1.6	1.1	1.0
Total gas production	**7.8**	5.6	6.8
Total production			
Quantity in Mboe	**3,206.3**	3,154.1	13,050.4
Quantity in Mboepd	**35.6**	34.7	35.7

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.

NORWAY

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013 – 31 Mar 2013 3 months**	1 Jan 2012 – 31 Mar 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Alvheim	15%	11.5	12.3	11.8
Volund	35%	13.1	13.2	13.1
Gaupe	40%	2.0	–	2.3
		26.6	25.5	27.2

The Alvheim field continues to sustain a high production level following two new infill wells being put on production during 2012. The net production from the Alvheim field during the reporting period was below expectations due to the shut-in of two production wells in January 2013 due to well integrity issues. The loss of production from the two wells was partially offset by production optimisation from the remaining wells and excellent uptime performance on the Alvheim FPSO. The two shut-in wells will be worked over in the second half of 2013 and are scheduled to be put back into production in early 2014. The cost of operations for the Alvheim field, excluding well intervention and project work, was below USD 5 per barrel during the reporting period.

The Volund field production during the reporting period has exceeded expectations due to better than expected reservoir performance and the Alvheim FPSO uptime performance also being ahead of expectations. During 2012 an additional Volund development well was drilled and put onstream early in 2013. The cost of operations for the Volund field during the reporting period was below USD 2.50 per barrel.

Production from the Gaupe field during the reporting period has been in line with expectations.

[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).

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	Late 2013	12.0 Mboepd
PL340	Bøyla	15%	October 2012	21 MMboe	Late 2014	19.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	186 MMboe	Late 2015	100.0 Mboepd

Edvard Grieg

The development is progressing on schedule and within budget. Construction and engineering work on the jacket, topside and export pipelines is ongoing.

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.

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.

Brynhild

The Brynhild subsea template and manifolds were installed in April 2013. The development involves the drilling of four wells tied back to the existing Shell operated Pierce field infrastructure in the United Kingdom sector of the North Sea. The Maersk Guardian jack-up rig will commence development drilling in the second quarter of 2013 following the completion of the currently drilling Carlsberg exploration well on PL495 (WI 60%). Topside modification work on the Pierce FPSO is scheduled to commence in the summer of 2013 when the FPSO will go to shore in Scotland. First production from the Brynhild field is still expected in the fourth quarter of 2013.

Bøyla

The Bøyla field will be developed as a 28 km subsea tie-back to the Alvheim FPSO. The field will be developed with two production wells and one water injection well with the drilling programme scheduled to commence in late 2013. Fabrication of the field's subsea structures has commenced.

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 15 wells have now been drilled on the Johan Sverdrup field. During the reporting period two wells and one side track were completed and one additional appraisal well has commenced drilling.

Well 16/2-16, drilled in 2012 in the northeastern flank of the Johan Sverdrup field on PL501, encountered a total of 55 metres gross reservoir thickness (Jurassic sequence). The oil water contact was encountered at the same depth as for well 16/2-13A to the east at 1,925 metres below Mean Sea Level (MSL), resulting in an oil bearing reservoir column at this location of approximately 1 metre. In February 2013 the side-track 16/2-16AT2 drilled approximately 1,000 metres to the west of 16/2-16, was successfully completed encountering a gross reservoir thickness of 70 metres with a gross oil column of 30 metres of mostly excellent reservoir quality within the Jurassic reservoir sequence. The oil water contact encountered was roughly at 1,934 metres below MSL which is at the same level as that of well 16/2-10 to the west of 16/2-16. This oil water contact is roughly 10 to 12 metres deeper than elsewhere on the Johan Sverdrup field.

In March 2013, the well 16/3-5 in the southeastern part of the Johan Sverdrup field on PL501 was successfully completed. The well encountered a 30 metre gross oil column with 14 metres of Upper Jurassic sandstone of excellent quality and 16 metres of Zechstein Group carbonate of varying reservoir quality. The oil top reservoir was encountered shallow to prognosis. Both the Upper Jurassic and the Zechstein sections were production tested with low production rates achieved from the Zechstein section and a production rate of 4,700 bopd achieved from the Upper Jurassic section through a restricted 48/64 choke. The well test confirmed the exceptional quality of the Upper Jurassic reservoir at this location.

In March 2013, the Norwegian Ministry of Petroleum and Energy announced that the well 16/5-3 on PL502 (Lundin Petroleum no working interest), adjacent to PL501 and PL265 was successfully completed. The well encountered a gross oil column of 13.5 metres of high quality Jurassic reservoir and confirmed reservoir and pressure communication with the rest of the Johan Sverdrup field. Whilst Lundin Petroleum has no ownership in this licence, this data point gives valuable information for future appraisal drilling in the southern part of the Johan Sverdrup field in PL501.

In April 2013, the appraisal well 16/2-17S, was drilled on the Fault Margin location on PL265. The well confirms the extension of good Jurassic reservoir close to the Fault Margin and is currently being flow tested. The well will be sidetracked to test the potential extension of the Johan Sverdrup field to the west (Cliffhanger South location) of the current assumed boundary of the field.

2013 appraisal well programme on Johan Sverdrup

Licence	Operator	Lundin Petroleum 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		Well ongoing
PL501	Lundin Petroleum	40%	16/2-21 (proposed B)	Q2 2013		
PL265	Statoil	10%	Cliffhanger, North	Q3 2013		
PL501	Lundin Petroleum	40%	16/3-6 (proposed C)	Mid-year 2013		
PL501	Lundin Petroleum	40%	Proposed E or G locations	Q3/Q4 2013		

The table above outlines the drilled, currently drilling and the remaining appraisal wells planned to be drilled on Johan Sverdrup in 2013.

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

Exploration

Three exploration wells have been completed in Norway so far this year. The Luno II well has resulted in a further exploration discovery in the Utsira High area.

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	Well ongoing
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	Mid-year 2013	Torvastad	40%	Lundin Petroleum	
PL544		Q3 2013	Biotitt	40%	Lundin Petroleum	
PL625		Q4 2013	Kopervik	40%	Lundin Petroleum	
PL359		Q4 2013	Luno II appraisal	40%	Lundin Petroleum	
Utgard High						
PL330		Q3 2013	Sverdrup	30%	RWE Dea	

Barents Sea				
PL492	Q3 2013	Gohta	40%	Lundin Petroleum
PL659	Q4 2013	Langlitinden	20%	Det norske oljeselskap

The above table is subject to change due to rig allocation and well results.

The drilling of the Ogna prospect in PL453S (WI 35%) in the southern North Sea was completed in February 2013 as a dry hole. The well 8/5-1, operated by Lundin Petroleum, was drilled to its target depth of 2,340 metres below MSL and has been plugged and abandoned.

In March 2013, Lundin Petroleum, as operator, completed the drilling of well 16/1-17 targeting the Jorvik prospect, situated in a separate basin, east of the Edvard Grieg field in the Utsira High area in PL338 (WI 50%). The well drilled to a depth of 2,044 below MSL and did encounter moveable oil. The pressure data indicates that the petroleum system is similar to that of the Edvard Grieg field and the Luno South discovery, however the reservoir section of conglomeratic and pebbly sandstone proved to be tight. The reservoir section was successfully cored prior to the well being plugged and abandoned as a non-commercial discovery.

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 structure span across two separate reservoir segments, containing gross contingent resources of 25 – 120 MMboe in the southern segment and gross prospective resources of 10 – 40 MMboe in the northern segment. Appraisal drilling in PL359 is being evaluated, with a well possible later this year, to further delineate the southern reservoir segment which at the high end of the resource range is likely to extend into PL410 (WI 70%) to the east of PL359. The lower end of the contingent resource range only reflects the northern part of the southern reservoir segment directly proven by the well. The well has been production tested and flowed at over 2,000 bopd through a 48/64 inch choke with a gas to oil ratio of 1,100 scf/bbl. The well proved the presence of a Jurassic/Triassic reservoir with a gross oil column of 45 metres and proved an oil water contact at 1,950 metres below MSL. The oil is saturated and in contact with a gas cap at the top of the reservoir. The well also proved a sand sequence of 280 metres with fair reservoir quality. A comprehensive coring and logging programme has been carried out and pressure data indicates that the petroleum system in the Luno II discovery is different to that seen at Edvard Grieg and Johan Sverdrup. The Luno II discovery is the fifth discovery Lundin Petroleum has made in the Utsira High area following discoveries on Edvard Grieg/Tellus, Apollo, Luno South and Johan Sverdrup.

Licence awards
In January 2013, Lundin Petroleum was awarded seven exploration licences in the 2012 APA licensing round of which two are operated by Lundin Petroleum. Four of the seven licences awarded are in the North Sea, two in the Norwegian Sea and one in the Barents Sea. Lundin Petroleum has submitted several licence applications for the 22nd Norwegian licensing round with awards expected to be announced by the Ministry of Petroleum and Energy in the second quarter of 2013.

During the reporting period PL576 was relinquished.

CONTINENTAL EUROPE

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013 – 31 Mar 2013 3 months**	1 Jan 2012 – 31 Mar 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
France				
– Paris Basin	100%	2.3	2.3	2.3
– Aquitaine Basin	50%	0.4	0.6	0.5
Netherlands	Various	2.2	2.0	1.9
		4.9	4.9	4.7

France
The redevelopment of the Grandville field in the Paris Basin has been completed and the remaining wells from this redevelopment were brought onstream during the fourth quarter of 2012.

The Netherlands
The Vinkega-2 gas discovery in the Gorredijk concession (WI 7.75%) commenced production in 2012 and construction of an additional pipeline was finished in April 2013.

Lundin Petroleum is participating in two exploration wells onshore Netherlands in 2013.

SOUTH EAST ASIA

Malaysia

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 billion cubic feet (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 interpretation of the Emerald 3D survey on SB307 is continuing and is expected to be completed in the second quarter of 2013.

One exploration well is planned to be drilled offshore Sabah in 2013.

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 holds one oil discovery called Bertam and one gas discovery called Tembakau.

Conceptual development studies of the Bertam discovery on Block PM307 (WI 75%) are substantially complete in relation to a potential development of the Bertam field and a final development decision will be taken in 2013. A 3D seismic acquisition programme over the northern part of Block PM307 and southern part of Block PM319 (WI 75%) was completed during the reporting period. The interpretation of this seismic is ongoing. The 300 bcf Tembakau gas discovery made in 2012 will likely be appraised as part of the next offshore Peninsular Malaysia drilling campaign.

Block PM308A (WI 35%) contains the Janglau and Rhu oil discoveries. A further exploration well targeting the Ara prospect on Block PM308A has been completed in the first quarter 2013 as an oil discovery, although the discovery is currently considered to be non-commercial. The Ara-1 well was drilled to a total depth of 4,030 metres below MSL and encountered nine thin oil bearing sands in a high pressure intra-rift section extending over a vertical interval of 800 metres.

Two exploration/appraisal wells offshore Peninsular Malaysia will be drilled in 2013.

Indonesia
Lundin Petroleum’s assets in Indonesia are located offshore, in the Natuna Sea and onshore South Sumatra. The Indonesian assets consist of approximately 23,000 km² of exploration acreage and one producing field onshore Sumatra.

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013 – 31 Mar 2013 3 months**	1 Jan 2012 – 31 Mar 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Singa	25.9%	1.6	1.2	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 100%) is planned to commence in 2013 with a well and a sidetrack targeting the Balqis and Boni prospects.

Gurita
Following the completion of the interpretation of the 3D seismic acquisition of 950 km² acquired in 2012, it has been decided that the 2013 exploration well on the Gurita Block (WI 100%) will be targeting the Gloria A prospect. Gloria A prospect is a fault-dip closure on the south flank of the Jemaja High, with stacked closures defined by 2012 3D seismic at multiple levels for Oligocene aged fluvial and alluvial sands that have been proven in many wells in the Natuna Basin.

South Sokang
A 3D seismic acquisition programme of 1,000 km² is planned to be completed in 2013 on the South Sokang Block (WI 60%).

OTHER AREAS

Russia

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013 – 31 Mar 2013 3 months**	1 Jan 2012 – 31 Mar 2012 3 months	1 Jan 2012 – 31 Dec 2012 12 months
Onshore Komi Republic	50%	2.5	2.8	2.7

In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery, Morskaya, was made in 2008. The discovery is deemed to be strategic, due to its offshore location, by the Russian Government under the Foreign Strategic Investment Law (FSIL). As a result a 50 percent ownership by a state owned company is required prior to appraisal and development. Discussions continue with third parties to meet the requirements of the FSIL.

FINANCIAL REVIEW

Result
The net result for the three month period ended 31 March 2013 amounted to MUSD 47.0 (MUSD 47.2). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 48.2 (MUSD 48.8) representing earnings per share of USD 0.16 (USD 0.16).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 276.2 (MUSD 309.2) representing EBITDA per share of USD 0.89 (USD 0.99). Operating cash flow for the reporting period amounted to MUSD 260.0 (MUSD 166.6) representing operating cash flow per share of USD 0.84 (USD 0.54).

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 327.6 (MUSD 364.6) and is 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 331.4 (MUSD 359.2). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 101.58 (USD 107.40) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 112.57 (USD 118.60) per barrel. The Alvheim and Volund field crude cargoes sold during the reporting period, which represented 62 percent (61 percent) of the total volumes sold, averaged USD 3.20 (USD 4.08) per barrel over Dated Brent for the pricing period for each lifting.

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

Sales Average price per boe expressed in USD	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil sales			
Norway			
– Quantity in Mboe	2,114.8	2,048.8	8,270.1
– Average price per boe	*115.33*	*123.06*	*115.29*
France			
– Quantity in Mboe	213.1	279.4	1,041.1
– Average price per boe	*108.52*	*119.50*	*110.44*
Netherlands			
– Quantity in Mboe	0.6	0.6	1.7
– Average price per boe	*104.80*	*107.07*	*100.09*
Russia			
– Quantity in Mboe	215.7	265.3	981.6
– Average price per boe	*79.94*	*77.75*	*77.23*
Tunisia			
– Quantity in Mboe	–	198.4	227.5
– Average price per boe	*–*	*111.77*	*108.14*
Total crude oil sales			
– Quantity in Mboe	**2,544.2**	2,792.5	10,522.0
– Average price per boe	***111.76***	*117.59*	*110.90*
Gas and NGL sales			
Norway			
– Quantity in Mboe	390.6	268.7	1,513.9
– Average price per boe	*77.06*	*61.18*	*64.18*
Netherlands			
– Quantity in Mboe	195.9	185.3	704.2
– Average price per boe	*65.22*	*60.35*	*60.18*

Indonesia			
– Quantity in Mboe	131.8	97.8	338.1
– Average price per boe	*31.87*	*32.49*	*32.43*
Total gas and NGL sales			
– Quantity in Mboe	**718.3**	551.8	2,556.2
– Average price per boe	***65.55***	*55.82*	*59.69*
Total sales			
– Quantity in Mboe	**3,262.5**	3,344.3	13,078.2
– Average price per boe	***101.58***	*107.40*	*100.89*

The oil produced in Russia is sold on either the Russian domestic market or exported into the international market. 45 percent (39 percent) of Russian sales for the reporting period were on the international market at an average price of USD 110.01 per barrel (USD 116.30 per barrel) with the remaining 55 percent (61 percent) of Russian sales being sold on the domestic market at an average price of USD 54.91 per barrel (USD 53.21 per barrel).

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

The change in under/over lift position amounted to MUSD -8.6 (MUSD 2.4) and primarily related to Norway where sales volumes were higher than production volumes for the reporting period and reduced the underlift position at 31 December 2012.

Other revenue amounted to MUSD 4.8 (MUSD 3.0) for the reporting period and included the quality differential compensation received from the Vilje field owners to the Alvheim and Volund field owners in Norway, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 44.0 (MUSD 56.7) and are detailed in the table below. The comparatives have been restated for the reclassification of the change in under/over lift from production costs to revenue.

Production costs	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cost of operations			
– In MUSD	26.6	25.2	105.6
– In USD per boe	*8.28*	*7.98*	*8.09*
Tariff and transportation expenses			
– In MUSD	6.5	6.8	29.7
– In USD per boe	*2.02*	*2.17*	*2.27*
Royalty and direct taxes			
– In MUSD	11.9	12.5	51.3
– In USD per boe	*3.70*	*3.97*	*3.93*
Change in inventory position			
– In MUSD	-1.0	11.7	14.8
– In USD per boe	*-0.28*	*3.69*	*1.13*
Other			
– In MUSD	–	0.5	1.8
– In USD per boe	*–*	*0.17*	*0.14*
Total production costs			
– In MUSD	**44.0**	56.7	203.2
– In USD per boe	***13.72***	*17.98*	*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 26.6 (MUSD 25.2) and includes cost of operations of MUSD 3.9 (MUSD –) associated with the Gaupe field, Norway, which came onstream on 31 March 2012. In the comparative reporting period, there is MUSD 4.8 associated with the Oudna field, Tunisia, which was decommissioned in the third quarter of 2012.

The cost of operations per barrel for the reporting period was in line with guidance given at the Capital Market Day in February 2013. Due to additional costs associated with well intervention work on the Alvheim field, scheduled to be performed in the second half of 2013, the cost of operations per barrel for 2013 is forecast to be approximately USD 1 per barrel over the guidance of USD 9.25 per barrel.

Royalty and direct taxes includes 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 23.95 (USD 23.05) 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 57.60 (USD 56.28) per exported barrel for the reporting period.

Change in inventory position amounted to a credit of MUSD 1.0 in the reporting period compared to a MUSD 11.7 charge in the comparative period. There was a lifting of inventory from the Ikdam FPSO on the Oudna field, Tunisia, in the comparative period resulting in a MUSD 11.4 charge to production costs.

Depletion and decommissioning costs
Depletion charges amounted to MUSD 43.0 (MUSD 41.4) and are detailed in Note 3. Norway contributed 73 percent of the total depletion charge for the reporting period at an average rate of USD 13.20 per barrel. The depletion charge for the reporting period is in line with Capital Market Day guidance.

Exploration costs
Exploration costs for the reporting period amounted to MUSD 72.0 (MUSD 8.9) 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 first quarter of 2013, MUSD 71.4 (MUSD 0.6) of exploration costs relating to Norway were expensed. The cost of the Ogna well along with associated licence costs on PL453S and the Jorvik well on PL338 were expensed for amounts of MUSD 43.8 and MUSD 24.2 respectively.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 8.3 (MUSD 0.5 credit) which included non-cash credits of MUSD 1.7 (MUSD 8.2) in relation to the Group's Long-term Incentive Plan (LTIP) scheme.

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 6 percent to SEK 141.00 per share during the reporting period compared to an 8 percent decrease from SEK 169.20 per share during the first quarter of 2012. Lundin Petroleum has mitigated the cash exposure of the LTIP by purchasing its own shares. For more detail refer to the remuneration section below.

Fixed asset depreciation charges for the reporting period amounted to MUSD 0.9 (MUSD 0.8).

Financial income
Financial income for the reporting period amounted to MUSD 0.9 (MUSD 0.6) and is detailed in Note 4.

Financial expenses
Financial expenses for the reporting period amounted to MUSD 10.5 (MUSD 27.3) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 1.3 (MUSD 1.4). An additional amount of interest of MUSD 2.6 (MUSD 1.6) 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 0.4 (MUSD 4.1). During the reporting period there was an exchange loss of MUSD 3.4 (MUSD 4.1) on the non-USD denominated intercompany loans and working capital balances and this loss was partly offset by a realised exchange gain of MUSD 3.0 (MUSD -) on settled foreign exchange hedges.

A provision for the costs of site restoration is recorded in the balance sheet at the discounted value of the estimated future cost. The effect of the discount is unwound each year and charged to the income statement. An amount of MUSD 1.6 (MUSD 1.2) has been charged to the income statement in the reporting period.

The amortisation of the deferred financing fees amounted to MUSD 2.2 (MUSD 1.3) for the reporting period and relates 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. The charge for the comparative period relates to the previous loan facility.

Loan facility commitment fees for the reporting period amounted to MUSD 4.9 (MUSD 0.3). The increase over the comparative period relates to the commitment fees on the undrawn portion of the larger USD 2.5 billion financing facility entered into in 2012.

Tax
The tax charge for the reporting period amounted to MUSD 103.7 (MUSD 184.2) and is detailed in Note 6.

The current tax charge for the reporting period amounted to MUSD 23.5 (MUSD 141.3) of which MUSD 17.0 (MUSD 132.0) relates to Norway. The current tax charge for the reporting period for Norway is lower than the comparative period primarily as a result of higher development and exploration expenditure spent in the first quarter of 2013 compared to the first quarter of 2012 as shown in the tables below.

The deferred tax charge for the reporting period amounted to MUSD 80.2 (MUSD 42.9) 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 79.7 (MUSD 40.1).

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 69 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 is driven by Norway where the tax rate is 78 percent reduced by the effect of an additional tax deduction on development expenditure.

Non-controlling interest
The net result attributable to non-controlling interest for the reporting period amounted to MUSD -1.2 (MUSD -1.6) and relates 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 2,970.1 (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- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway	178.7	46.9	369.0
France	2.0	10.6	29.2
Netherlands	0.9	1.6	8.5
Indonesia	–	0.1	-0.4
Russia	0.4	1.2	7.5
	182.0	60.4	413.8

An amount of MUSD 178.7 (MUSD 46.9) of development expenditure was incurred in Norway during the reporting period, of which MUSD 158.0 (MUSD 30.6) was invested in the Brynhild and Edvard Grieg field developments. In the comparative period, MUSD 10.6 was spent in France, mainly on the Grandville field redevelopment.

Exploration and appraisal expenditure in MUSD	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway	124.8	47.3	323.2
France	0.6	0.4	9.8
Indonesia	1.8	1.2	16.4
Russia	1.1	1.5	3.6
Malaysia	17.5	3.5	100.5
Other	0.1	1.3	3.8
	145.9	55.2	457.3

Exploration and appraisal expenditure of MUSD 124.8 was incurred in Norway during the reporting period, mainly on the appraisal drilling of the Johan Sverdrup field and exploration drilling of the Ogna and Jorvik prospects on PL453S and PL338 respectively. In the comparative period, MUSD 47.3 was spent in Norway mainly on Johan Sverdrup field appraisal drilling.

MUSD 17.5 (MUSD 3.5) was spent in Malaysia during the reporting period 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 and PM319.

Tangible fixed assets amounted to MUSD 50.2 (MUSD 49.4) and include an amount of MUSD 33.6 (MUSD 32.5) relating to the Ikdam FPSO vessel. The balance of MUSD 16.6 (MUSD 16.9) relates to real estate and office fixed assets.

Financial assets amounted to MUSD 40.6 (MUSD 44.1). Other shares and participations amounted to MUSD 16.6 (MUSD 20.0) and mainly relates 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 asset amounted to MUSD 13.5 (MUSD 13.3) and is mainly relating to the part of the tax loss carry forwards in the Netherlands that are expected to be utilised.

Current assets
Inventories amounted to MUSD 18.9 (MUSD 18.7) and include both hydrocarbon inventories and well supplies.

The underlift position amounted to MUSD 17.0 (MUSD 26.4) of which MUSD 14.4 (MUSD 24.6) related to the Norwegian producing fields.

Derivative instruments amounted to MUSD 2.9 (MUSD 9.1) and relates to the mark-to-market on outstanding foreign currency hedges contracts entered into in 2012 and 2013.

Prepaid expenses and accrued income amounted to MUSD 26.6 (MUSD 32.9) and includes prepaid operational insurance and insurance on the Edvard Grieg development project, Norway.

Cash and cash equivalents amounted to MUSD 125.1 (MUSD 97.4). Cash balances are held to meet operational and investment requirements.

Non-current liabilities
The provision for site restoration amounted to MUSD 184.2 (MUSD 190.5) and relates to future decommissioning obligations.

The provision for deferred taxes amounted to MUSD 975.3 (MUSD 942.2) of which MUSD 837.8 (MUSD 802.8) relates 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.

Included in non-current liabilities is the non-current portion of the provision for Lundin Petroleum's LTIP scheme which amounted to MUSD 66.1 (MUSD 67.1).

Financial liabilities amounted to MUSD 491.7 (MUSD 384.2). Bank loans amounted to MUSD 535.0 (MUSD 432.0) and relates to the outstanding loan under the Group's USD 2.5 billion revolving borrowing base facility. Capitalised financing fees amounted to MUSD 43.3 (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 25.0 (MUSD 22.6) and mainly arise from the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities
Tax liabilities amounted to MUSD 127.4 (MUSD 170.0) of which MUSD 120.2 (MUSD 163.6) relates to Norway.

Joint venture creditors amounted to MUSD 219.1 (MUSD 213.9) and relates to the high level of development and drilling activity in Norway and Malaysia.

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 -11.5 (MSEK 6.5) for the reporting period.

The result includes general and administrative expenses of MSEK 12.2 (MSEK 5.9 credit), guarantee fees of MSEK 0.7 (MSEK –) and interest income from a group company of MSEK 0.1 (MSEK 8.7 interest expense). The general and administrative expenses in the reporting period are impacted by the variation in the provision for the Group's LTIP and the credit in the comparative period was a result of a decrease in the Lundin Petroleum share price in the first quarter 2012.

Pledged assets of MSEK 11,962.7 (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 0.1 (MUSD 0.1) from ShaMaran Petroleum for the provision of office and other services.

The Group paid MUSD 0.1 (MUSD –) for services rendered by Vostok Nafta.

LIQUIDITY
On 25 June 2012, Lundin Petroleum entered into a seven year senior secured revolving borrowing base facility of USD 2.5 billion with a group of 25 banks to provide funding for Lundin Petroleum's ongoing exploration expenditure and development costs, particularly in Norway. The USD 2.5 billion financing facility is a revolving borrowing base facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 31 March 2013 is MUSD 1,833.4 (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 five Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas), in respect of the six operated Blocks in Malaysia. Bank guarantees have been issued in support of the work commitments in relation to these PSCs and the outstanding amount of the bank guarantees at 31 March 2013 was MUSD 42.4. In addition, bank guarantees have been issued to cover work commitments in Indonesia amounting to MUSD 2.4 and in Tunisia for MUSD 1.5 relating to tax disputes.

SUBSEQUENT EVENTS
No significant events have occurred after the end of the reporting period that are expected to have a substantial effect on this financial report.

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.

As at 31 March 2013, Lundin Petroleum held 7,368,285 of its own shares.

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 2010, 2011 and 2012 Unit Bonus Plans outstanding as at 31 March 2013 were 207,841, 248,958 and 359,295 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 7,368,285 of its own shares which mitigates against the exposure of the LTIP. The Lundin Petroleum share price at 31 March 2013 was SEK 141.00. The provision for the Phantom Option Plan amounted to MUSD 75.8 including social charges as at 31 March 2013 and the market value of the shares held at 31 March 2013 was MUSD 159.2. 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.

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 further 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

In the first quarter of 2013, the Group also entered into a three year fixed interest rate swap, starting 31 March 2013, in respect of MUSD 500 of borrowings, fixing the LIBOR rate at approximately 0.57 percent per annum for the duration of the hedge.

Under IAS 39, subject to hedge effectiveness testing, all of the hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. At 31 March 2013, a current asset has been recognised amounting to MUSD 2.9 (MUSD 9.1) representing the fair value of the outstanding short term currency hedging contracts. In addition, a current liability has been recognised of MUSD 0.9 (MUSD –) representing the fair value of the outstanding short term interest rate and a non-current liability of MUSD 1.6 (MUSD –) representing the fair value of the long term outstanding interest rate and currency hedges.

EXCHANGE RATES

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

	31 Mar 2013		31 Mar 2012		31 Dec 2012	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	5.6276	5.8665	5.7867	5.6933	5.8148	5.5639
1 USD equals Euro	0.7573	0.7809	0.7628	0.7487	0.7778	0.7579
1 USD equals Rouble	30.4088	31.0517	30.1660	29.4212	31.0546	30.5665
1 USD equals SEK	6.4318	6.5250	6.7524	6.6229	6.7725	6.5045

CONSOLIDATED INCOME STATEMENT IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Revenue[1]	1	**327.6**	364.6	1,375.8
Cost of sales				
Production costs[1]	2	-44.0	-56.7	-203.2
Depletion and decommissioning costs		-43.0	-41.4	-191.4
Exploration costs		-72.0	-8.9	-168.4
Impairment costs of oil and gas properties		–	–	-237.5
Gross profit	3	**168.6**	257.6	575.3
General, administration and depreciation expenses		-8.3	0.5	-31.8
Operating profit		**160.3**	258.1	543.5
Result from financial investments				
Financial income	4	0.9	0.6	27.3
Financial expenses	5	-10.5	-27.3	-48.5
		-9.6	-26.7	-21.2
Profit before tax		**150.7**	231.4	522.3
Income tax expense	6	-103.7	-184.2	-418.4
Net result		**47.0**	47.2	103.9
Net result attributable to the shareholders of the Parent Company:		48.2	48.8	108.2
Net result attributable to non-controlling interest:		-1.2	-1.6	-4.3
Net result		**47.0**	47.2	103.9
Earnings per share – USD[2]		0.16	0.16	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- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Net result	**47.0**	47.2	103.9
Other comprehensive income			
Items that may be subsequently reclassified to profit or loss:			
Exchange differences foreign operations	-44.3	52.6	61.6
Cash flow hedges	-8.8	0.2	9.2
Available-for-sale financial assets	-3.0	9.4	16.1
Income tax relating to other comprehensive income	2.3	–	-2.3
Other comprehensive income, net of tax	-53.8	62.2	84.6
Total comprehensive income	**-6.8**	109.4	188.5
Total comprehensive income attributable to:			
Shareholders of the Parent Company	-4.5	106.5	190.2
Non-controlling interest	-2.3	2.9	-1.7
	-6.8	109.4	188.5

CONSOLIDATED BALANCE SHEET IN SUMMARY

Expressed in MUSD	Note	**31 March 2013**	31 December 2012
ASSETS			
Non-current assets			
Oil and gas properties	7	2,970.1	2,864.4
Other tangible assets		50.2	49.4
Financial assets	8	40.6	44.1
Total non-current assets		**3,060.9**	2,957.9
Current assets			
Receivables and inventories	9	216.0	238.4
Cash and cash equivalents		125.1	97.4
Total current assets		**341.1**	335.8
TOTAL ASSETS		**3,402.0**	3,293.7
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,177.9	1,182.4
Non-controlling interest		65.4	67.7
Total equity		**1,243.3**	1,250.1
Non-current liabilities			
Provisions	10	1,231.7	1,204.6
Financial liabilities	11	491.7	384.2
Other non-current liabilities		25.0	22.6
Total non-current liabilities		**1,748.4**	1,611.4
Current liabilities			
Other current liabilities	12	400.6	423.4
Provisions	10	9.7	8.8
Total current liabilities		**410.3**	432.2
TOTAL EQUITY AND LIABILITIES		**3,402.0**	3,293.7

CONSOLIDATED STATEMENT OF CASH FLOW IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cash flow from operations				
Net result		47.0	47.2	103.9
Adjustments for non-cash related items	14	229.4	251.8	1,056.9
Gain on sale of asset		–	–	-1.1
Interest received		0.2	0.1	3.5
Interest paid		-3.6	-1.5	-8.9
Income taxes paid		-60.0	-86.8	-428.8
Changes in working capital		41.1	-47.0	93.5
Total cash flow from operations		**254.1**	163.8	819.0
Cash flow from investments				
Investment in oil and gas properties		-327.7	-115.6	-919.4
Investment in office equipment and other assets		-2.8	-1.0	-9.7
Investment in subsidiaries		–	–	-10.2
Decommissioning costs paid		-0.1	–	-18.6
Other payments		-0.2	-0.4	-3.2
Total cash flow from investments		**-330.8**	-117.0	-961.1
Cash flow from financing				
Changes in long-term liabilities		103.7	19.5	225.7
Financing fees paid		–	–	-49.2
Purchase of own shares		–	–	-8.7
Total cash flow from financing		**103.7**	19.5	167.8
Change in cash and cash equivalents		27.0	66.3	25.7
Cash and cash equivalents at the beginning of the period		97.4	73.6	73.6
Currency exchange difference in cash and cash equivalents		0.7	-2.3	-1.9
Cash and cash equivalents at the end of the period		**125.1**	137.6	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	**–**	**57.7**	–	**48.8**	**2.9**	**109.4**
Balance at 31 March 2012	**0.5**	**395.5**	**662.6**	**48.8**	**72.3**	**1,179.7**
Total comprehensive income	**–**	**24.3**	**–**	**59.4**	**-4.6**	**79.1**
Transactions with owners						
Purchase of own shares	–	-8.7	–	–	–	**-8.7**
Balance at 31 December 2012	**0.5**	**411.1**	**662.6**	**108.2**	**67.7**	**1,250.1**
Transfer of prior year net result	**–**	**–**	108.2	-108.2	**–**	**–**
Total comprehensive income	**–**	**-52.7**	**–**	**48.2**	**-2.3**	**-6.8**
Balance at 31 March 2013	**0.5**	**358.4**	**770.8**	**48.2**	**65.4**	**1,243.3**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Revenue, MUSD	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil	284.3	328.4	1,169.0
Condensate	1.1	0.4	3.3
Gas	46.0	30.4	147.2
Net sales of oil and gas	**331.4**	359.2	1,319.5
Change in under/over lift position	-8.6	2.4	30.7
Other revenue	4.8	3.0	25.6
Revenue	**327.6**	364.6	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- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cost of operations	26.6	25.2	105.6
Tariff and transportation expenses	6.5	6.8	29.7
Direct production taxes	11.9	12.5	51.3
Change in inventory position	-1.0	11.7	14.8
Other	–	0.5	1.8
	44.0	56.7	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- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway			
Crude oil	243.9	252.1	953.4
Condensate	0.8	–	2.3
Gas	29.3	16.5	94.9
Net sales of oil and gas	**274.0**	268.6	1,050.6
Change in under/over lift position	-9.3	3.6	31.4
Other revenue	1.6	1.6	6.5
Revenue	**266.3**	273.8	1,088.5
Production costs	-17.3	-12.4	-65.5
Depletion and decommissioning costs	-31.6	-33.0	-154.1
Exploration costs	-71.4	-0.6	-103.1
Impairment costs of oil and gas properties	–	–	-205.8
Gross profit	**146.0**	227.8	560.0
France			
Crude oil	23.1	33.4	115.0
Net sales of oil and gas	23.1	33.4	115.0
Change in under/over lift position	-0.3	-0.8	–
Other revenue	0.5	0.4	2.6
Revenue	**23.3**	33.0	117.6
Production costs	-7.6	-7.9	-29.9
Depletion and decommissioning costs	-3.0	-3.0	-11.7
Exploration costs	–	–	-5.0
Gross profit	**12.7**	22.1	71.0

Note 3. Segment information cont., MUSD	**1 Jan 2013-31 Mar 2013 3 months**	1 Jan 2012-31 Mar 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Netherlands			
Crude oil	0.1	0.1	0.2
Condensate	0.3	0.4	1.0
Gas	12.5	10.7	41.4
Net sales of oil and gas	**12.9**	11.2	42.6
Change in under/over lift position	1.0	-0.1	-0.7
Other revenue	0.5	0.3	12.2
Revenue	**14.4**	11.4	54.1
Production costs	-3.0	-2.8	-12.4
Depletion and decommissioning costs	-4.2	-2.8	-10.4
Exploration costs	–	–	-0.6
Gross profit	**7.2**	5.8	30.7
Indonesia			
Gas	4.2	3.2	10.9
Net sales of oil and gas	**4.2**	3.2	10.9
Change in under/over lift position	–	-0.3	–
Revenue	**4.2**	2.9	10.9
Production costs	-1.1	-1.3	-5.5
Depletion and decommissioning costs	-2.9	-1.5	-5.6
Exploration costs	-0.1	-6.8	-7.4
Gross profit	**0.1**	-6.7	-7.6
Russia			
Crude oil	17.2	20.6	75.8
Net sales of oil and gas	**17.2**	20.6	75.8
Revenue	**17.2**	20.6	75.8
Production costs	-15.0	-16.2	-65.2
Depletion and decommissioning costs	-1.3	-1.1	-4.3
Impairment costs of oil and gas properties	–	–	-31.7
Gross profit	**0.9**	3.3	-25.4
Other			
Crude oil[1]	–	22.2	24.6
Net sales of oil and gas	–	22.2	24.6
Other revenue	2.2	0.7	4.3
Revenue	**2.2**	22.9	28.9
Production costs	–	-16.1	-24.7
Depletion and decommissioning costs	–	–	-5.3
Exploration costs[2]	-0.5	-1.5	-52.3
Gross profit	**1.7**	5.3	-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 0.4 (MUSD 0.1) has been expensed in the reporting period relating to Malaysia.

Total			
Crude oil	284.3	328.4	1,169.0
Condensate	1.1	0.4	3.3
Gas	46.0	30.4	147.2
Net sales of oil and gas	**331.4**	359.2	1,319.5
Change in under/over lift position	-8.6	2.4	30.7
Other revenue	4.8	3.0	25.6
Revenue	**327.6**	364.6	1,375.8
Production costs	-44.0	-56.7	-203.2
Depletion and decommissioning costs	-43.0	-41.4	-191.4
Exploration costs	-72.0	-8.9	-168.4
Impairment costs of oil and gas properties	–	–	-237.5
Gross profit	**168.6**	257.6	575.3

Note 4. Financial income, MUSD	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Interest income	0.5	0.6	5.1
Foreign currency exchange gain, net	–	–	6.2
Guarantee fees	–	–	0.2
Gain on consolidation of subsidiary	–	–	13.4
Other	0.4	–	2.3
	0.9	0.6	27.3

Note 5. Financial expenses, MUSD	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Interest expense	1.3	1.4	6.8
Foreign currency exchange loss, net	0.4	4.1	–
Result on interest rate hedge settlement	–	0.2	0.2
Unwinding of site restoration discount	1.6	1.2	5.1
Amortisation of deferred financing fees	2.2	1.3	6.6
Loan facility commitment fees	4.9	0.3	10.3
Impairment of other shares	–	18.6	18.6
Other	0.1	0.2	0.9
	10.5	27.3	48.5

Note 6. Income tax expense, MUSD	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Current tax	23.5	141.3	341.3
Deferred tax	80.2	42.9	77.1
	103.7	184.2	418.4

Note 7. Oil and gas properties, MUSD	**31 Mar 2013**	31 Dec 2012
Norway	1,806.4	1,702.3
France	209.9	216.8
Netherlands	60.8	65.8
Indonesia	95.7	96.9
Russia	596.9	599.2
Malaysia	200.4	183.4
	2,970.1	2,864.4

Note 8. Financial assets, MUSD	**31 Mar 2013**	31 Dec 2012
Other shares and participations	16.6	20.0
Bonds	9.2	9.5
Deferred tax	13.5	13.3
Other	1.3	1.3
	40.6	44.1

Note 9. Receivables and inventories, MUSD	**31 Mar 2013**	31 Dec 2012
Inventories	18.9	18.7
Trade receivables	125.7	125.9
Underlift	17.0	26.4
Corporate tax	6.9	4.0
Joint venture debtors	14.5	11.5
Derivative instruments	2.9	9.1
Prepaid expenses and accrued income	26.6	32.9
Other	3.5	9.9
	216.0	238.4

Note 10. Provisions, MUSD	**31 Mar 2013**	31 Dec 2012
Non-current:		
Site restoration	184.2	190.5
Deferred tax	975.3	942.2
Long-term incentive plan	66.1	67.1
Derivative instruments	1.6	–
Pension	1.5	1.5
Other	3.0	3.3
	1,231.7	1,204.6
Current:		
Long-term incentive plan	9.7	8.8
	9.7	8.8
	1,241.4	1,213.4

Note 11. Financial liabilities, MUSD	**31 Mar 2013**	31 Dec 2012
Bank loans	535.0	432.0
Capitalised financing fees	-43.3	-47.8
	491.7	384.2

Note 12. Other current liabilities, MUSD	**31 Mar 2013**	31 Dec 2012
Trade payables	12.6	15.7
Overlift	0.6	0.5
Tax liabilities	127.4	170.0
Accrued expenses and deferred income	28.7	8.3
Joint venture creditors	219.1	213.9
Derivative instruments	0.9	–
Other	11.3	15.0
	400.6	423.4

Note 13. Financial instruments,
MUSD

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

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

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

31 March 2013 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	16.2	–	0.4
- Bonds	9.2	–	–
- Derivative instruments - current	–	2.1	–
	25.4	**2.1**	**0.4**
Liabilities			
- Derivative instruments – non-current	–	1.6	–
- Derivative instruments – current	–	0.9	–
	–	**2.5**	**–**

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 - 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 7 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- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Exploration costs	72.0	8.8	168.5
Depletion, depreciation and amortisation	43.9	42.2	189.3
Current tax	23.5	141.3	341.3
Deferred tax	80.2	42.9	77.1
Impairment of oil and gas properties	–	–	237.5
Impairment of other shares	–	18.6	18.6
Long-term incentive plan	1.9	-10.0	13.0
Other	7.9	8.0	11.6
	229.4	251.8	1,056.9

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-31 Mar 2013 3 months**	1 Jan 2012-31 Mar 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Revenue	**-0.1**	9.3	71.0
General and administration expenses	-12.2	5.9	-84.6
Operating profit	**-12.3**	15.2	-13.6
Result from financial investments			
Financial income	0.9	–	807.1
Financial expenses	-0.1	-8.7	-31.3
	0.8	-8.7	775.8
Profit before tax	**-11.5**	6.5	762.2
Income tax expense	–	–	–
Net result	**-11.5**	6.5	762.2

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-31 Mar 2013 3 months**	1 Jan 2012-31 Mar 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Net result	-11.5	6.5	762.2
Other comprehensive income	–	–	–
Total comprehensive income	**-11.5**	6.5	762.2
Total comprehensive income attributable to:			
Shareholders of the Parent Company	-11.5	6.5	762.2
	-11.5	6.5	762.2

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in MSEK	**31 March 2013**	31 December 2012
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Receivables from group companies	16.1	21.4
Total non-current assets	**7,887.9**	7,893.2
Current assets		
Receivables	16.7	20.7
Cash and cash equivalents	0.7	1.1
Total current assets	**17.4**	21.8
TOTAL ASSETS	**7,905.3**	7,915.0
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,858.3	7,869.8
Non-current liabilities		
Provisions	36.4	36.4
Total non-current liabilities	**36.4**	36.4
Current liabilities		
Current liabilities	10.6	8.8
Total current liabilities	**10.6**	8.8
TOTAL EQUITY AND LIABILITIES	**7,905.3**	7,915.0
Pledged assets	11,962.7	11,911.6

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cash flow from operations			
Net result	-11.5	6.5	762.2
Adjustment for non-cash related items	-0.3	0.1	-725.2
Changes in working capital	5.7	-2.2	-6.4
Total cash flow from operations	**-6.1**	**4.4**	30.6
Cash flow from investments			
Change in long term financial fixed assets	–	–	0.1
Change in long term receivables	5.7	–	–
Total Cash flow from investments	**5.7**	–	0.1
Cash flow from financing			
Change in long-term liabilities	–	-7.6	29.1
Purchase of own shares	–	–	-62.4
Total cash flow from financing	**–**	-7.6	-33.3
Change in cash and cash equivalents	-0.4	-3.2	-2.6
Cash and cash equivalents at the beginning of the period	1.1	3.8	3.8
Currency exchange difference in cash and cash equivalents	–	–	-0.1
Cash and cash equivalents at the end of the period	**0.7**	0.6	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	**–**	**–**	**–**	**–**	**6.5**	**6.5**
Balance at 31 March 2012	**3.2**	**861.3**	**2,551.8**	**3,753.7**	**6.5**	**7,176.5**
Total comprehensive income	**–**	**–**	**–**	**–**	**755.7**	**755.7**
Transactions with owners						
Purchase of own shares	–	–	-62.4	–	–	-62.4
Balance at 31 December 2012	**3.2**	**861.3**	**2,489.4**	**3,753.7**	**762.2**	**7,869.8**
Transfer of prior year net result	–	–	–	762.2	-762.2	–
Total comprehensive income	**–**	**–**	**–**	–	**-11.5**	**-11.5**
Balance at 31 March 2013	**3.2**	**861.3**	**2,489.4**	**4,515.9**	**-11.5**	**7,858.3**

KEY FINANCIAL DATA

Financial data (MUSD)	**1 Jan 2013- 31 Mar 2013 3 months**	1 Jan 2012- 31 Mar 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Revenue[1]	327.6	364.6	1,375.8
EBITDA	276.2	309.2	1,144.1
Net result	47.0	47.2	103.9
Operating cash flow	260.0	166.6	831.4
Data per share (USD)			
Shareholders' equity per share	3.79	3.56	3.81
Operating cash flow per share	0.84	0.54	2.68
Cash flow from operations per share	0.82	0.53	2.64
Earnings per share	0.16	0.16	0.35
Earnings per share fully diluted	0.16	0.16	0.35
EBITDA per share	0.89	0.99	3.68
Dividend per share	–	–	–
Number of shares issued at period end	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	310,542,295	311,027,942	310,542,295
Weighted average number of shares for the period	310,542,295	311,027,942	310,735,227
Share price			
Quoted price at period end (SEK)	141.00	141.80	149.50
Quoted price at period end (CAD)	21.87	21.55	22.87
Key ratios			
Return on equity (%)	4	4	9
Return on capital employed (%)	9	17	35
Net debt/equity ratio (%)	37	10	30
Equity ratio (%)	37	40	38
Share of risk capital (%)	65	70	66
Interest coverage ratio	120	15	75
Operating cash flow/interest ratio	205	11	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, 7 May 2013

C. Ashley Heppenstall
President and CEO

The financial information relating to the three month period ended 31 March 2013 has not been subject to review by the auditors of the Company.

Financial information

The Company will publish the following reports:

- The six month report (January – June 2013) will be published on 7 August 2013.
- The nine month report (January – September 2013) will be published on 6 November 2013.
- The year end report (January – December 2013) will be published on 5 February 2014.

The AGM will be held on 8 May 2013 in Stockholm, Sweden.

For further information, please contact:

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This information has been made public in accordance with the Securities Market Act (SFS 2007:528) and/or the Financial Instruments Trading Act (SFS 1991:980).

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.

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.