LUNDIN PETROLEUM – PRESS RELEASE

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

Stockholm 6 February 2013

YEAR END REPORT 2012

HIGHLIGHTS

Twelve months ended 31 December 2012 (31 December 2011)

- Production of 35.7 Mboepd (33.3 Mboepd)
- Operating income of MUSD 1,345.1 (MUSD 1,269.5)
- EBITDA of MUSD 1,144.1 (MUSD 1,012.1)
- Operating cash flow of MUSD 831.4 (MUSD 676.2)
- Net result of MUSD 103.9 (MUSD 155.2)
- New USD 2.5 billion seven year secured revolving borrowing base facility signed on 25 June 2012
- PDOs approved for the Edvard Grieg and Bøyla fields, Norway
- Pre-Unit agreement signed for the Johan Sverdrup field
- Extensive appraisal drilling on the Johan Sverdrup field
- Geitungen oil discovery of between an estimated 140 and 270 MMboe gross recoverable resources[1] located north of the Johan Sverdrup field within PL265

Fourth quarter ended 31 December 2012 (31 December 2011)

- Production of 35.9 Mboepd (34.7 Mboepd)
- EBITDA of MUSD 289.8 (MUSD 244.8)
- Operating cash flow of MUSD 237.4 (MUSD 89.4)
- Net result of MUSD -52.7 (MUSD -14.0)
- Tembakau-1 gas discovery of 306 bcf on Block PM307, offshore Peninsular Malaysia
- New Block PM319 awarded offshore Peninsular Malaysia
- Acquisition of an additional 20 percent interest in the Brynhild field, offshore Norway

	1 Jan 2012- 31 Dec 2012 12 months	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Production in Mboepd	35.7	35.9	33.3	34.7
Operating income in MUSD	1,345.1	342.6	1,269.5	323.0
Net result in MUSD	103.9	-52.7	155.2	-14.0
Net result attributable to shareholders of the Parent Company in MUSD	108.2	-51.5	160.1	-12.5
Earnings/share in USD[1]	0.35	-0.16	0.51	-0.05
Diluted earnings/share in USD[1]	0.35	-0.16	0.51	-0.05
EBITDA in MUSD	1,144.1	289.8	1,012.1	244.8
Operating cash flow in MUSD	831.4	237.4	676.2	89.4

[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).

[1]Estimated by PL265 operator, Statoil

Dear fellow shareholders,

2012 was yet another successful year for our Company. We have exceeded our production forecasts once again and this, coupled with our low operating costs and cash taxes, has resulted in a record operating cash flow of more than MUSD 830 for the year.

Since the end of 2001, we have increased our share price by over 50 times to a current market capitalisation exceeding USD 8 billion. This has been done without any issuance of new cash equity other than employee stock options. Our strong operating cash flow coupled with the availability of a new USD 2.5 billion bank facility means that we will be able to grow our business without further dilution to our shareholders. We have the ability to quadruple our existing production to over 150,000 boepd over the next seven years through the development of our existing Norwegian discoveries Brynhild, Bøyla, Edvard Grieg and Johan Sverdrup. This growth in production will have a major positive impact on our future financial performance. At the same time we will continue to concentrate on increasing our resource base through a major exploration drilling programme focused predominantly on Norway and South East Asia.

Financial Performance

For the twelve months ending 31 December 2012, we generated record operating cash flow of MUSD 831.4 and EBITDA of MUSD 1,144.1 which represent increases of 23 percent and 13 percent respectively when compared to the previous year. Profit after tax for the period was MUSD 103.9 and was negatively impacted by non-cash exploration and asset impairment costs incurred in the fourth quarter. The nature of our business involves the drilling of successful exploration wells, such as Johan Sverdrup where the asset continues to be valued in our balance sheet based upon historical costs, as well as unsuccessful wells where the costs are immediately expensed. We have increased the exploration budget as our business has grown and this will likely mean that our profitability will continue to be negatively impacted by unsuccessful wells. However the valuation of our business will continue to be driven by our ability to discover new resources through our exploration drilling programmes - even though this will not immediately be reflected in the profitability of the Company.

Reserves and Resources

Lundin Petroleum's success has been due to our ability to increase our resource base. Today we have net resources, including 2P reserves and 2C contingent resources of over 1 billion barrels recoverable. These resources are predominantly oil. Our 2P recoverable reserves at the end of 2012 were 201.5 million barrels of oil equivalent. Whilst last year's reserve replacement ratio was lower than in previous years, I think everyone would agree that this will change when the contingent resources from the Johan Sverdrup field in Norway are booked as reserves. There is little doubt that the Johan Sverdrup field is commercial but reserves will not be booked until the signing of a unitisation agreement and the submission of the field development plan both scheduled for the end of 2014.

The Johan Sverdrup appraisal programme is ongoing and will continue throughout 2013 with at least four more appraisal wells. Johan Sverdrup is the largest discovery in the North Sea since the mid 1980's covering a large area. 12 appraisal wells, including the discovery well, have already been drilled or are currently drilling and the preparation of a geological and reservoir model to incorporate all the acquired data is ongoing. Statoil as a working operator for the Johan Sverdrup field development has decided to delay the release of updated resource numbers until later this year when the appraisal programme and a conceptual development plan will be completed.

Production

Production for 2012 was 35,700 boepd which was again in the upper half of our original 32,000 - 38,000 boepd production guidance. Strong performance from the Alvheim and Volund fields, offshore Norway more than made up for lower production than forecast from the Gaupe field, offshore Norway and the early termination of production from the Oudna field, offshore Tunisia. I am pleased that we have consistently achieved our production forecasts over recent years despite the uncertainties and risks in our business.

In 2013 we expect our net production to average between 33,000 boepd and 38,000 boepd for the year and to exit the year at in excess of 40,000 boepd when the Brynhild field reaches plateau production.

We reiterate our guidance of production in excess of 70,000 boepd by the end of 2015 following first production from the Edvard Grieg field.

Development

Our three development projects in Norway are all progressing satisfactorily.

We have increased our equity interest in the Brynhild field to 90 percent. Brynhild is a subsea tieback to Shell's Pierce FPSO facility in the United Kingdom with a forecast gross plateau production of 12,000 boepd. The Maersk Guardian rig which is currently drilling exploration wells for us will commence the four Brynhild development wells during the second quarter of 2013. The Edvard Grieg development project is also progressing satisfactorily as we progress through the execution phase. It is very encouraging to see recent photographs of the Kværner Verdal yard on the west coast of Norway where the Edvard Grieg jacket is starting to take shape. The Edvard Grieg project remains on budget and on schedule for first oil in late 2015.

We are in the process of awarding a front end engineering (FEED) contract for the Bertam field development project, offshore Malaysia and still plan to make a field investment decision in 2013.

Appraisal

Five new appraisal wells were drilled on Johan Sverdrup in 2012 by Lundin Petroleum and Statoil. Each of the new wells provides important information for development planning as well as an understanding of the size of the resource. The resource estimates are primarily influenced by depth conversion, reservoir thickness and quality and oil/water contact assumptions. One additional well is ongoing and Lundin Petroleum will drill at least a further two appraisal wells in PL501 this year and Statoil will drill two wells in PL265 and one in PL502.

The forward plan still remains for Statoil as "working operator" of Johan Sverdrup to complete a conceptual development plan by the end of 2013 and a development plan submission by the end of 2014.

Exploration

We are very excited about our 2013 exploration programme which involves the drilling of 18 exploration wells in Norway, South East Asia, France and the Netherlands. The budget of over USD 460 million will be the largest in the Company's history and will be predominantly focused on Norway which will account for about 75 percent of the expenditure.

In Norway, we will concentrate on three core exploration themes being:

1. To find further resources in the Utsira High Area close to the existing Edvard Grieg and Johan Sverdrup discoveries
2. To explore in the frontier Barents Sea area where we believe there is excellent potential for additional oil discoveries
3. To unearth a new core area

We are drilling six exploration wells in the Utsira High area with high expectations for the Luno II (PL359), Kopervik (PL625) and Torvastad (PL501) prospects which all individually have the potential to be material discoveries. In the Barents Sea we continue to increase our acreage in the ongoing licensing rounds and are today one of the largest players in the region. Our exploration drilling programme will continue in 2013 with the drilling of the Gotha prospect in PL492. We have acquired a large acreage position in the northern Norwegian Sea targeting an underexplored Jurassic high area where we will drill a large prospect in 2013 in PL330. I hope this will result in the opening up of the area which contains numerous prospects and leads in both PL330 and adjoining licences which we have secured.

We continue to make good progress with our exploration programme in Malaysia. Following the successful appraisal of the Bertam discovery in PM307 we acquired new 3D seismic on trend with the discovery. This led to the discovery of the 300 bcf Tembakau gas discovery in 2012 also located in PM307. I believe Tembakau which is a material discovery close to existing gas infrastructure has the potential to be commercialised. It is clear that the key to exploration success in Malaysia is to have access to modern 3D seismic data and we plan to continue our proactive exploration of the area in 2013.

Oil Market and Lundin Petroleum

The markets have begun 2013 with oil prices increasing. There is a growing realisation that the world economy is slowly recovering and if this continues will result in an increase in oil demand. China is the largest growth market for oil and with its growth rates appearing to bottom out I think we can expect this to further support demand. The geopolitical climate remains an issue with increasing instability in North Africa and little signs of improvement in the Middle East. This will put further pressure on forecasts of oil supply which I believe are already over estimated. Unconventional oil production in North America is certainly increasing but I believe the increased supply will be easily accommodated through growing demand from the developing world and supply declines from mature production areas. As a result I believe oil prices will remain firm.

There is no new information to report in respect of the allegations regarding our historical operations in Sudan and Ethiopia. We have and will continue to assist the Swedish prosecutor as requested in relation to his investigation.

In respect of our ongoing commitment to Corporate Social Responsibility we have re-affirmed our engagement towards transparency by becoming an Extractive Industries Transparency Initiative (EITI) Supporting Company. As an EITI Supporting Company, Lundin Petroleum will continue to report in accordance with EITI requirements in Norway and will promote transparency especially within the oil and gas industry and contribute to the fight against corruption.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 6 February 2013

OPERATIONAL REVIEW

Production

Production for the twelve month period ended 31 December 2012 (reporting period) amounted to 35.7 thousand barrels of oil equivalents per day (Mboepd) and was comprised as follows:

Production in Mboepd	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Crude oil				
Norway	23.3	22.9	21.1	22.3
France	2.8	2.8	3.1	3.0
Russia	2.7	2.5	3.1	3.0
Tunisia	0.1	–	0.7	0.6
Total crude oil production	**28.9**	**28.2**	28.0	28.9
Gas				
Norway	3.9	4.3	2.1	2.4
Netherlands	1.9	1.8	2.0	2.0
Indonesia	1.0	1.6	1.2	1.4
Total gas production	**6.8**	**7.7**	5.3	5.8
Total production				
Quantity in Mboe	**13,050.4**	**3,300.8**	12,151.5	3,188.2
Quantity in Mboepd	**35.7**	**35.9**	33.3	34.7

EUROPE

Norway

Production

in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**
Alvheim	15%	11.8	11.9
Volund	35%	13.1	12.5
Gaupe	40%	2.3	2.8
		27.2	**27.2**

The net production in Norway to Lundin Petroleum for the reporting period was 27,200 barrels of oil equivalent per day (boepd).

The net production from the Alvheim field during the reporting period exceeded expectations due to the excellent uptime performance of the FPSO at over 95 percent and the cancellation of the anticipated second quarter shut down of the SAGE system. An Alvheim development well was drilled during the first half of 2012 and was tied in and put on production in October 2012. In January 2013 the Alvheim partnership was awarded additional acreage to the north of the Alvheim field through the 2012 APA licensing round. The work programme for this new acreage involves 3D seismic reprocessing with the objective of identifying potential new drilling targets in the Alvheim area. The cost of operations for the Alvheim field for the reporting period was below USD 5 per barrel excluding certain planned well intervention work during the third quarter of 2012.

Volund field production during the reporting period exceeded expectations due to better than expected reservoir performance and the Alvheim FPSO uptime. An additional Volund development well has been drilled and is expected to come on production in the first quarter of 2013. The cost of operations for the Volund field for the reporting period was below USD 2 per barrel driven by lower than expected production costs and better than expected production.

First production from the Gaupe field in PL292 was achieved on 31 March 2012. Production from the Gaupe field has been below forecast since the commencement of production. Technical analysis indicates that the two production wells are connected to lower hydrocarbon volumes than was forecast prior to production startup. Consequently the reserves have been reduced based on the conservative assumption that no additional production wells will be drilled.

Development

The Norwegian Parliament approved the Edvard Grieg (WI 50%) plan of development in June 2012. The development plan incorporates the provision for the coordinated development solution of the Edvard Grieg field with the nearby Ivar Aasen field (formerly Draupne) located in PL001B and operated by Det norske oljeselskap ASA. A plan of development was submitted for the Ivar Aasen field in December 2012.

The Edvard Grieg field is estimated to contain 186 million barrels of oil equivalents (MMboe) of gross reserves with first production expected in late 2015 and forecast gross peak production of approximately 100.0 Mboepd. The gross capital cost of the Edvard Grieg field development is estimated at USD 4 billion to include platform, pipelines and 15 wells. Contracts have been awarded to Kværner covering engineering, procurement and construction of the jacket and the topsides for the platform and to Rowan Companies for a jack up rig to drill the development wells. Saipem has been awarded the contract for marine installation. The development is progressing well and construction work on the jacket is ongoing. Construction and engineering work on the jacket, topside and export pipelines will continue throughout 2013. An appraisal well is planned to be drilled in the south eastern part of the Edvard Grieg reservoir in 2013 to target additional resources.

A plan of development of the Brynhild field in PL148 (WI 90%) was approved by the Norwegian Ministry of Petroleum and Energy in November 2011. The Brynhild field contains gross reserves of 23.1 MMboe and is expected to produce at an estimated gross plateau production rate of 12.0 Mboepd with first oil forecast in late 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 development is well advanced in respect of engineering and construction work and the Maersk Guardian jack-up rig will commence development drilling in the second quarter of 2013. In December 2012, Lundin Petroleum announced that it had completed a transaction with Talisman Energy to acquire an additional 20 percent interest in PL148, taking Lundin Petroleum's interest in the field to 90 percent.

A plan of development for the Bøyla field in PL340 (WI 15%) was submitted in June 2012 and approved by the Ministry of Petroleum and Energy in October 2012. The Bøyla field contains gross reserves of 21 MMboe and will be developed as a 28 km subsea tieback to the Alvheim FPSO. First oil from the Bøyla field is expected in the fourth quarter of 2014 at a gross plateau production rate of 19.0 Mboepd.

Appraisal

Lundin Petroleum discovered the Avaldsnes field in PL501 (WI 40%) in 2010. In 2011, Statoil made the Aldous Major South discovery on the neighboring 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.

During the reporting period, a total of four appraisal wells and two side-tracks on PL501 have been drilled and a further two appraisal wells on PL265 have also been completed.

In January 2012, a third appraisal well, 16/5-2S, located on PL501 was completed. The objective of the well was to delineate the southern flank of the Johan Sverdrup, PL501 discovery. The well, despite encountering good Jurassic sandstone reservoir, was deep to prognosis and as a result the reservoir was below the oil water contact.

In March 2012, a further appraisal well, 16/2-11, was completed on PL501 which encountered a 54 metre gross oil column in Upper and Middle Jurassic sandstone reservoir in an oil-down-to situation. The reservoir was encountered at depth prognosis. A sidetrack of the well was successfully completed encountering a 35 metre gross oil column confirming similar excellent reservoir thickness and quality.

In the third quarter of 2012, the drilling of the appraisal well 16/2-13S on the north eastern part of the Johan Sverdrup discovery and a side-track well 16/2-13A were successfully completed. The results from the wells were excellent in respect of reservoir quality and thickness, validating the field geological model and confirming a deeper oil water contact at this location. Well 16/2-13S encountered a 25 metre gross oil column in Upper and Middle Jurassic sandstone reservoir in an oil-down-to situation. The side-track well 16/2-13A encountered a gross reservoir column of approximately 22 metres, of which 12 metres were above the oil water contact. The oil water contact was established at approximately 1,925 metres below Mean Sea Level (MSL) which is approximately 3 metres deeper than observed in earlier PL501 wells.

In December 2012 the drilling of appraisal well 16/2-16 in the north eastern flank of the discovery was successfully completed. The well encountered a total of 15 metres of sand within a 60 metre 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 MSL, resulting in an oil bearing reservoir column at this location of approximately 1 metre. A further side-track 16/2-16AT2 was drilled to the west of well 16/2-16 with a step-out of approximately 1,000 metres. The side-track, which was successfully completed in January 2013, encountered a gross oil column of 30 metres with largely excellent reservoir qualities within the Jurassic reservoir sequence. Oil was encountered at the same depth as at well 16/2-10 on PL265 which is the deepest oil water contact encountered in Johan Sverdrup so far.

Appraisal well 16/3-5 in the south eastern part of Johan Sverdrup in PL501 is currently drilling with results expected in the first quarter of 2013.

In November 2012, Statoil announced the successful completion of appraisal well 16/2-14 on Johan Sverdrup in PL265. Well 16/2-14 was drilled in a northwestern segment of Johan Sverdrup approximately 6 km northwest of the discovery well 16/2-6 drilled by Lundin Petroleum. The well 16/2-14 encountered an approximately 30 metre reservoir section saturated with oil. The well confirmed good reservoir quality at this location.

In early January 2013, the Norwegian Petroleum Directorate announced the successful completion of appraisal well 16/2-15 drilled in the southwestern part of Johan Sverdrup in PL265. The well was drilled 5 km southeast of the discovery well 16/2-6 and encountered a gross oil column of 30 metres of which 20 metres contained excellent reservoir quality.

It is likely that at least two further appraisal wells will be drilled in both PL501 and PL265 in 2013.

Lundin Petroleum, as operator of PL501, has signed a Pre-Unit agreement with the partners within PL501 and PL265 for the joint field development of the Johan Sverdrup field. Statoil has been elected as working operator for the pre-unit phase. 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 to be submitted by the fourth quarter of 2014 and first oil production by the end of 2018.

Exploration

During the reporting period a total of five exploration wells have been completed in Norway.

In June 2012, the drilling of exploration well 2/8-18S targeting the Clapton prospect on PL440s (WI 18%) was completed by the operator Faroe Petroleum. The well, which is located in the southern North Sea, did not encounter hydrocarbons. The well was drilled to a depth of 2,619 metres below MSL and was plugged and abandoned.

In August 2012, the exploration well 16/2-12 targeting the Geitungen structure in PL265 (WI 10%) was successfully completed as an oil discovery. The well, which was located to the north of the Johan Sverdrup discovery and to the south of 16/2-9S Aldous Major North discovery, has proved a gross oil column of 35 metres in high quality sandstone of Jurassic age. Oil was also proven in the basement rock. Data acquisition in the well, including coring, wireline logging and fluid sampling, indicates that the Geitungen structure is in communication with the Johan Sverdrup discovery made by Lundin Norway in 2010. Preliminary calculations indicate that the size of the Geitungen discovery is between 140 and 270 million barrels of gross recoverable oil[1]. Geitungen will be developed as part of the Johan Sverdrup development.

In October 2012, Lundin Petroleum announced the results of the Albert well in PL519 (WI 40%). The main objective of well 6201/11-3 was to test Cretaceous and Triassic age sandstones of a multiple target structure. The well encountered oil in thin Cretaceous reservoir sequence at the predicted level for the primary target. The thin thickness and uncertain distribution of the reservoir do not give a basis for resource estimation at this stage and as such the discovery is currently deemed uncommercial. Further potential exists within the Albert structure if thicker Cretaceous reservoir section in this large structure can be identified. The Triassic secondary reservoir was tight without movable hydrocarbons. A minor column of movable hydrocarbons were also encountered in a Paleocene secondary target. Further exploration activity is planned in this area in 2014 with the drilling of the Storm prospect in PL555 where Lundin Petroleum holds a 60 percent interest and is operator.

In October 2012, Lundin Petroleum announced that exploration well 7220/10-1 in PL533 (WI 20%) had discovered gas/condensate in the Salina structure located on the west flank of the Loppa High in the Barents Sea. The well has proved two gas columns in sandstone of Cretaceous and Jurassic age. Data acquisition in the well, including coring, wireline logging and fluid sampling, has proven good reservoir quality in the sandstone. Preliminary calculations, made by the Norwegian Petroleum Directorate, give a range of gross discovered volume in the Salina structure of between 174 and 246 billion cubic feet (bcf) (29 and 41 MMboe) of recoverable gas/condensate. Further resource upside exists in fault compartments associated with the Salina structure.

In November 2012, Lundin Petroleum successfully completed the exploration well 7120/6-3 S in PL490 (WI 50%) in the Barents Sea. The well was located 10 km to the north west of the Snøhvit field and was targeting stacked targets Snurrevad and Juksa at the lower Cretaceous and upper Jurassic reservoirs The preliminary analysis of a cored section of the reservoir indicate thin oil bearing sands in a 8 to 9 metres zone at the top of a 25 metre lower Cretaceous sand sequence. No reservoir was found to be present in the Snurrevad target at the Jurassic level. The thin oil bearing sands in the Juksa discovery are unlikely to be commercial however it is encouraging that the well encountered oil bearing sands as opposed to gas.

Lundin Petroleum announced in July 2012 that it had entered into farm-out agreements to reduce its holdings in a number of licences. Spring Energy Norway AS has acquired a 10 percent interest in PL490, with Lundin Petroleum retaining 50 percent and Norwegian Energy Company ASA has acquired a 10 percent interest in PL492, with Lundin Petroleum retaining 40 percent; both licences are located in the Barents Sea. Explora Petroleum AS has acquired a 30 percent interest in PL544 and Lundin Petroleum retains 40 percent; the licence is located in the North Sea. The Norwegian authorities have approved these farm-out agreements. In January 2012, Lundin Petroleum was awarded ten exploration licences in the APA 2011 licensing round of which four are operated by Lundin Petroleum. In January 2013, Lundin Petroleum was awarded a further seven exploration licences in the APA 2012 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

[1]Estimated by PL265 operator, Statoil

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 first half of 2013.

Lundin Petroleum's exploration programme in Norway for 2013 will consist of 10 exploration wells with a continued focus on the Utsira High area with six exploration wells targeting similar play concepts as Johan Sverdrup and Edvard Grieg. In addition, two exploration wells will be drilled in the southern North Sea, one of which is currently drilling, one well will be drilled in the Barents Sea and one well will be drilled on PL330 (WI 30%) in the northern Norwegian Sea. Rigs have been secured for all of the 2013 exploration wells.

France

Production

in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**
Paris Basin	100%	2.3	2.3
Aquitaine Basin	50%	0.5	0.5
		2.8	**2.8**

The redevelopment of the Grandville field in the Paris Basin was substantially completed during the reporting period with the development wells brought onstream during the fourth quarter of 2012.

Two exploration wells were drilled in the reporting period. The Amaltheus exploration well in the Paris Basin on the Val des Marais concession (WI 100%) was successfully completed in the fourth quarter of 2012 as an oil discovery. The well has been put on long-term production test. A second exploration well targeting the Contault prospect in the Paris Basin on the Est Champagne concession (WI 100%) was completed during the fourth quarter of 2012 as a dry hole. Lundin Petroleum is drilling one exploration well in the Paris Basin in 2013. The Hoplites-1 well will be drilled on the Est Champagne concession (WI 100%) targeting the Nettancourt prospect.

The Netherlands

The net gas production to Lundin Petroleum from the Netherlands averaged 1.9 Mboepd for the reporting period. Development drilling on existing production assets is ongoing to optimise field recovery. The Vinkega-2 exploration well in the Gorredijk concession (WI 7.75%) was a gas discovery in the third quarter of 2012 and is currently planned to commence production in the first quarter of 2013.

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

Ireland

Following the completion of seismic studies on the Slyne Basin licence 04/06 (WI 50%), the licence partners are considering the way forward.

SOUTH EAST ASIA

Indonesia

Lematang (South Sumatra)

The net production to Lundin Petroleum from the Singa gas field (WI 25.9%) during the reporting period amounted to 1.0 Mboepd. Production in the reporting period has been negatively affected by well maintenance work which was completed in September 2012. Production during the fourth quarter averaged 1.6 Mboepd.

Baronang/Cakalang (Natuna Sea)

Exploration drilling on the Baronang Block (WI 100%) will commence in 2013.

South Sokang (Natuna Sea)

A 3D seismic acquisition programme is planned to be completed in 2013 on South Sokang (WI 60%).

Gurita (Natuna Sea)

A 3D seismic acquisition programme of 950 km² has been completed in 2012 on the Gurita Block (WI 100%) and an exploration well will be drilled in 2013.

Malaysia

East Malaysia, offshore Sabah

Lundin Petroleum holds two licences offshore Sabah in east Malaysia.

SB303 (WI 75%) contains the Tarap, Cempulut and Titik Terang gas discoveries with an estimated gross contingent resource of more than 270 bcf. Lundin Petroleum continues to evaluate the potential for commercialisation of these gas discoveries, most likely through a cluster development.

In September 2012, the Berangan-1 exploration well in SB303 was successfully completed as a gas discovery. The well penetrated a gross gas column of over 165 metres in the target mid-Miocene aged sands 10 km to the southeast of the Tarap gas discovery made by Lundin Petroleum in 2011, and 15 km to the south of the Cempulut gas discovery also made in 2011. The Baronang discovery is estimated to contain 69 bcf (11.5 MMboe) of gross contingent gas resources and it is likely that it will be included in a cluster development with the other SB303 gas discoveries.

In July 2012, the Tiga Papan 5 well in SB307/308 (WI 42.5%) targeting mid-Miocene aged sands of the Tiga Papan Unit was plugged and abandoned as a dry hole.

One exploration well will be drilled offshore Sabah in 2013.

Offshore Peninsular Malaysia
Lundin Petroleum holds four licences offshore Peninsular Malaysia.

In June 2011, Lundin Petroleum acquired a 75 percent working interest in Block PM307. A 2,100 km² 3D seismic acquisition programme was completed in 2011. In January 2012, the Bertam-2 appraisal well was successfully completed proving the continuity and quality of the K10 oil reservoir sandstone. Conceptual development studies are substantially complete in relation to a potential development of the Bertam field and a decision will be taken in 2013. In November 2012, Lundin Petroleum announced the Tembakau-1 well, drilled on Block PM307, as a gas discovery. The Tembakau-1 well was drilled to a total depth of 1,565 metres and encountered a series of stacked gas pay sands at the Miocene level. The net pay was 60 metres over five high quality sand intervals. Given the relatively close proximity to existing gas infrastructure coupled with the forecast strong demand for gas on Peninsular Malaysia the building blocks for a commercial development are present and further studies, will be undertaken to assess the commerciality of this discovery. It is estimated that the Tembakau discovery contains 306 bcf (51 MMboe) of gross contingent gas resources. A 3D seismic acquisition programme over the northern part of Block PM307 is currently ongoing. The 3D seismic acquisition is also stretching into the recently awarded Block PM319 (WI 75%).

Block PM308A (WI 35%) contains the Janglau and Rhu oil discoveries. A further exploration well targeting the Ara prospect on Block PM308A is currently drilling. The well is targeting the Oligocene intra-rift sands discovered by the Janglau exploration well drilled in 2011. An acquisition of 1,450 km² of new 3D seismic in PM308A was completed during the reporting period.

In Block PM308B (WI 75%) the Merawan Batu-1 exploration well was completed in October 2012 and plugged and abandoned as a dry hole.

In December 2012 Lundin Petroleum announced the award of a new block offshore Peninsular Malaysia. Block PM319 is operated by Lundin Petroleum with a 85 percent working interest with Petronas holding a 15 percent working interest. The block covers an area of approximately 8,400 km² and is located west of Block PM307 where Lundin Petroleum and Petronas have achieved success during 2012 with the appraisal of the Bertam oil field and the discovery of gas with the Tembakau-1 well. The area has very limited 3D coverage and work commitments include a full tensor gravity survey, 550 km² of 3D seismic and one wildcat exploration well.

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

RUSSIA
The net production to Lundin Petroleum from onshore assets located in the Komi Republic, Russia for the reporting period was 2.7 Mboepd. Production has been below expectations through the reporting period and consequently the remaining reserves as of 31 December 2012 have been reduced.

In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery was made on the Morskaya discovery 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.

AFRICA

Tunisia
The production from the Oudna field (WI 40%) for the first quarter of 2012 was 0.4 Mboepd and 0.1 Mboepd for the reporting period. Following storm damage to a flowline in March 2012, the Oudna field was shut-in. An assessment of repair solutions to the flowline was carried out and it was determined to be uneconomic to repair. During 2012, the Ikdam FPSO was disconnected from the Oudna field and the wells were permanently abandoned. During the reporting period Lundin Petroleum has increased its ownership in the Ikdam FPSO to 100 percent and will now seek new opportunities for the vessel.

Congo (Brazzaville)
With the relinquishment of its interest in the Block Marine XI licence (WI 18.75%) in June 2012 and the expiry of the Block Marine XIV licence (WI 21.55%) in October 2012, Lundin Petroleum has exited Congo (Brazzaville).

FINANCIAL REVIEW

Result

The net result for the twelve month period ended 31 December 2012 (reporting period) amounted to MUSD 103.9 (MUSD 155.2). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 108.2 (MUSD 160.1) representing earnings per share on a fully diluted basis of USD 0.35 (USD 0.51).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 1,144.1 (MUSD 1,012.1) representing EBITDA per share on a fully diluted basis of USD 3.68 (USD 3.25). Operating cash flow for the reporting period amounted to MUSD 831.4 (MUSD 676.2) representing operating cash flow per share on a fully diluted basis of USD 2.68 (USD 2.17).

Changes in the Group

On 27 August 2012, Lundin Petroleum acquired a further 60 percent equity in Ikdam Production SA, a company which owns the Ikdam FPSO, bringing its total ownership to 100 percent. The financial results of Ikdam Production SA are fully consolidated in the Group's financial statements from the end of August 2012.

Operating income

Net sales of oil and gas for the reporting period amounted to MUSD 1,319.5 (MUSD 1,257.7) and are detailed in Note 1. The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 100.89 (USD 101.04) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 111.67 (USD 111.26) per barrel. The Alvheim and Volund field crude cargoes sold during the reporting period averaged USD 3.53 (USD 3.87) per barrel over Dated Brent for the pricing period for each lifting.

Sales of oil and gas for the reporting period were comprised as follows:

Sales Average price per boe expressed in USD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Crude oil sales				
Norway				
- Quantity in Mboe	8,270.1	2,059.4	7,896.0	2,085.7
- Average price per boe	115.29	114.35	115.38	113.36
France				
- Quantity in Mboe	1,041.1	337.9	1,155.5	283.3
- Average price per boe	110.44	108.79	110.59	110.68
Netherlands				
- Quantity in Mboe	1.7	0.5	2.2	0.6
- Average price per boe	100.09	101.45	103.87	95.74
Russia				
- Quantity in Mboe	981.6	225.4	1,138.4	271.2
- Average price per boe	77.23	79.00	69.85	70.34
Tunisia				
- Quantity in Mboe	227.5	–	198.2	–
- Average price per boe	108.14	–	125.12	–
Total crude oil sales				
- Quantity in Mboe	**10,522.0**	**2,623.2**	10,390.3	2,640.8
- Average price per boe	**110.90**	**109.80**	110.25	109.46
Gas and NGL sales				
Norway				
- Quantity in Mboe	1,513.9	467.5	947.2	268.0
- Average price per boe	64.18	70.35	61.14	60.94
Netherlands				
- Quantity in Mboe	704.2	169.4	722.8	184.1
- Average price per boe	60.18	62.92	60.61	64.04
Indonesia				
- Quantity in Mboe	338.1	113.4	387.7	117.0
- Average price per boe	32.43	31.73	32.43	32.19
Total gas and NGL sales				
- Quantity in Mboe	**2,556.2**	**750.3**	2,057.7	569.1
- Average price per boe	**59.69**	**65.59**	54.50	52.26
Total sales				
- Quantity in Mboe	**13,078.2**	**3,373.5**	12,448.0	3,209.9
- Average price per boe	**100.89**	**99.97**	101.04	99.32

Sales quantities in a period can differ from production quantities as a result of permanent and timing differences. Timing differences can arise due to 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 oil produced in Russia is sold on either the Russian domestic market or exported into the international market. 45 percent (37 percent) of Russian sales for the reporting period were on the international market at an average price of USD 109.93 per barrel (USD 109.92 per barrel) with the remaining 55 percent (63 percent) of Russian sales being sold on the domestic market at an average price of USD 49.98 per barrel (USD 46.45 per barrel).

Other operating income amounted to MUSD 25.7 (MUSD 11.8) for the reporting period and includes MUSD 11.0 (MUSD -) relating to a pre-tax settlement of an equity redetermination that was agreed between the parties in Blocks K4a, K4b/K5a and K5b, offshore Netherlands, and MUSD 6.5 (MUSD 5.8) of income relating to a quality differential compensation payable from the Vilje field owners to the Alvheim and Volund field owners in Norway. The quality compensation adjustment in Norway arises as all three fields produce to the

Alvheim FPSO vessel and the oil is commingled to produce an Alvheim crude blend which is then sold. Also included in other operating income is 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 172.5 (MUSD 193.1) and are detailed in Note 2. The production costs in the reporting period includes a MUSD 15.9 credit for inventory movements compared to a MUSD 13.1 charge in the comparative period as explained below. The production and depletion costs per barrel of oil equivalent produced are detailed in the table below.

Production costs and depletion in USD per boe	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Cost of operations	8.09	8.86	8.43	8.89
Tariff and transportation expenses	2.27	2.63	1.88	1.64
Royalty and direct taxes	3.93	3.73	4.31	4.03
Changes in inventory/lifting position	-1.22	-0.61	1.08	-0.01
Other	0.14	–	0.18	0.17
Total production costs	**13.21**	**14.61**	15.88	14.72
Depletion [1]	14.26	14.64	13.59	13.72
Total cost per boe	**27.47**	**29.25**	29.47	28.44

[1] excludes decommissioning costs

The total cost of operations for the reporting period was MUSD 105.6 compared to MUSD 102.5 for the comparative period and includes cost of operations of MUSD 12.0 associated with the Gaupe field, Norway which came onstream on 31 March 2012. The cost of operations for the Oudna field, Tunisia was MUSD 8.6 for the reporting period compared to MUSD 17.0 for the comparative period following the shut-in of production in March 2012. The cost of operations per barrel for the reporting period was lower than the comparative period due mainly to the higher production.

The cost of operations per barrel for the fourth quarter of 2012 amounted to USD 8.86 per barrel and was higher than the previous quarters of 2012 due primarily to a planned well intervention campaign on fields in the Paris Basin, France. For 2012, the average cost of operations per barrel for the year was USD 8.09 per barrel which is in line with the prior guidance given at the end of the third quarter of USD 8.25 per barrel.

The tariff and transportation expenses for the reporting period amounted to MUSD 29.7 compared to MUSD 22.9 for the comparative period. Included in the reporting period are costs associated with the Gaupe field of MUSD 7.4.

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 22.92 (USD 21.21) 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 57.08 (USD 57.52) per barrel for the reporting period.

There are both permanent and timing differences that result in sales volumes not being equal to production volumes during a period. Changes to the hydrocarbon inventory and under or overlift positions result from these timing differences and an amount of MUSD 15.9 was credited to the income statement for the reporting period compared to a MUSD 13.1 charge for the comparative period. There was a net underlift movement of MUSD 18.5 on the Alvheim/Volund fields, Norway, where crude sales volumes during the reporting period were lower than production volumes compared to a MUSD 18.7 net overlift movement for the comparative period. In addition, the Gaupe field, Norway, was underlifted during the reporting period resulting in a MUSD 12.9 (MUSD -) credit to production costs. The Gaupe field hydrocarbons are processed across the non-operated Armada host platform and there is an allocation agreement whereby new fields compensate existing fields through volume for production deferred by the new production stream. The resultant underlift position is repaid by the existing fields in future periods. There were also liftings of inventory from the Ikdam FPSO on the Oudna field, Tunisia, resulting in a MUSD 14.6 (MUSD -6.2) charge to production costs in the reporting period.

Depletion and decommissioning costs

Depletion charges amounted to MUSD 186.2 (MUSD 165.1) and are detailed in Note 3. Norway contributed 83 percent of the total depletion charge for the reporting period at an average rate of USD 15.54 per barrel. The increase in depletion charges over the comparative period is mainly a result of the inclusion of the Gaupe field, Norway.

Decommissioning costs charged to the income statement in the reporting period amounted to MUSD 5.3 (MUSD -) and represent the costs of decommissioning the Oudna field, Tunisia, in excess of the provision for this work. The Oudna field was fully decommissioned in 2012.

Exploration costs
Exploration costs for the reporting period amounted to MUSD 168.5 (MUSD 140.0) and are detailed in Note 4. 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 fourth quarter of 2012, in Norway, the costs of the Albert well on PL519 and the Juksa well and associated licence costs on PL490 were expensed for amounts of MUSD 36.6 and MUSD 50.1 respectively. In Malaysia, the costs of drilling the Merawan Batu prospect and associated licence costs on PM308B of MUSD 36.1 were expensed. Other exploration costs amounting to MUSD 12.1 have also been expensed in the quarter.

In the third quarter of 2012, the Tiga Papan 5 well in SB307/308, offshore Sabah, east Malaysia was plugged and abandoned as a dry hole. The cost of the well and associated licence costs amounting to MUSD 9.2 were expensed.

During the first half of 2012, costs associated with the Clapton well on PL440S, Norway and the Rangkas Block, Indonesia were expensed.

Impairment costs
Impairment costs for the reporting period amounted to MUSD 237.5 (MUSD -) and are detailed in Note 5. Following poor performance since the start of production from the Gaupe field, Norway, the reserves have been reduced based on the conservative assumption that no further production wells will be drilled resulting in an impairment charge of MUSD 205.8. In addition, poor reservoir performance from the onshore Russian assets has led to an impairment charge of MUSD 31.7.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 31.7 (MUSD 67.0) of which MUSD 9.1 (MUSD 44.9) related to non-cash charges 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. The value of the awards, calculated using the Black and Scholes method, is applied to the vested portion of the outstanding LTIP awards including that of previous periods with the change in the provision being reflected in the income statement. The Lundin Petroleum share price decreased in the first half of 2012 and the reversal of part of the provision reported at 31 December 2011 resulted in a credit to the income statement in the reporting period up to 30 June 2012. The share price increased by approximately 24 percent as at 30 September 2012 compared to 30 June 2012, which resulted in an increase in the provision for LTIP at the balance sheet date and a corresponding charge to the income statement for the third quarter 2012. During the fourth quarter of 2012, the share price decreased by approximately 7 percent as at 31 December 2012 compared to 30 September 2012. Lundin Petroleum has mitigated the exposure of the LTIP by purchasing its own shares. For more detail refer to the remuneration section below.

Depreciation charges for the reporting period amounted to MUSD 3.1 (MUSD 2.6).

Financial income
Financial income for the reporting period amounted to MUSD 27.2 (MUSD 46.5) and is detailed in Note 7.

Interest income for the reporting period amounted to MUSD 5.1 (MUSD 4.1). The interest income in the fourth quarter of 2012 includes MUSD 1.3 in relation to the Brynhild transaction with Talisman Energy.

Net foreign exchange gains for the reporting period amounted to MUSD 6.2 (MUSD 8.9). During the reporting period, there was an exchange loss of MUSD 5.5 (MUSD -8.9) on the non-USD denominated intercompany loans and working capital balances and this loss was offset by a realised exchange gain of MUSD 11.7 (MUSD -) on settled foreign exchange hedges.

A gain on consolidation of a subsidiary of MUSD 13.4 (MUSD -) was reported in the third quarter of 2012 and relates to the accounting for the full consolidation of Ikdam Production SA (IPSA) following the acquisition of the outstanding 60 percent of the shares of the company at the end of August 2012. Lundin Petroleum already held 40 percent of the shares in IPSA which was acquired as part the Coparex acquisition in 2002. At the time of the Coparex acquisition, no value was assigned to the shares of IPSA and a provision was made against a loan to IPSA from the Group. Following the acquisition of the remaining 60 percent equity, a step-up in the carrying value of the existing 40 percent interest based on the fair value of the assets and liabilities of the company at the end of August 2012 was recorded and the provision made against the original loan was released.

An amount of MUSD 30.0 relating to the gain on sale of Africa Oil Corporation shares is included in financial income for the comparative period.

Financial expenses

Financial expenses for the reporting period amounted to MUSD 48.5 (MUSD 21.0) and are detailed in Note 8.

Interest expenses for the reporting period amounted to MUSD 6.8 (MUSD 5.4). An additional amount of interest of MUSD 3.4 (MUSD 1.4) associated with the funding of the Norwegian development projects was capitalised in the reporting period.

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 5.1 (MUSD 4.5) has been charged to the income statement for the reporting period.

The amortisation of the deferred financing fees for the reporting period amounted to MUSD 6.6 (MUSD 2.1) and relates to the expensing of the fees incurred in establishing the loan facility over the period of usage of that facility. Lundin Petroleum arranged a new USD 2.5 billion financing facility which was signed on the 25 June 2012 and the fees associated with this facility are being amortised on a going forward basis.

Loan facility commitment fees for the reporting period amounted to MUSD 10.3 (MUSD 1.0). 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 June 2012.

Lundin Petroleum owns 50 million shares in ShaMaran Petroleum which were acquired in 2009 in a non-cash transaction. The investment was booked at the fair value of the shares at the date of acquisition and under accounting rules, subsequent movements in the fair value of the shares were being recognised in other comprehensive income. In January 2012, ShaMaran Petroleum announced that it had relinquished its working interests in its operated Production Sharing Contract licences and, as such, it was considered that there had been a permanent diminution in the fair value of the shares of ShaMaran Petroleum held by Lundin Petroleum. As a result of the permanent diminution in the fair value of the shares, the cumulative loss recognised in other comprehensive income of MUSD 18.6 was reclassified from equity and recognised in the income statement in the first quarter of 2012. The subsequent gain on the shares since the impairment has been recognised in other comprehensive income.

Tax

The tax charge for the reporting period amounted to MUSD 418.4 (MUSD 574.4) and is detailed in Note 9.

The current tax charge for the reporting period amounted to MUSD 341.3 (MUSD 400.2) of which MUSD 311.8 (MUSD 365.6) relates to Norway. The Norwegian current tax charge for the reporting period is lower than the comparative period primarily as a result of higher development and exploration expenditure.

The deferred tax charge for the reporting period amounted to MUSD 77.1 (MUSD 174.2) and arises primarily where there is a difference in depreciation for tax and accounting purposes. In Norway, there is a net deferred tax charge for the reporting period of MUSD 80.4 (MUSD 166.2) which is net of a deferred tax release on the impairment of the Gaupe field amounting to MUSD 160.6 in the fourth quarter of 2012.

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 80 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 overall effective rate of tax is driven by Norway where the tax rate is 78 percent reduced by the effect of uplift on development expenditure for tax purposes. The effective rate is increased due to a number of non-tax adjusted items in the reporting period including the impairment of the ShaMaran shares, the Malaysian expensed exploration costs and certain general and administrative costs, as well as a lower tax credit on the exploration costs relating to the Rangkas Block, Indonesia. There is no tax expense associated with the financial income booked on full consolidation of Ikdam Production SA.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -4.3 (MUSD -4.9) 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 2,864.4 (MUSD 2,329.3) and are detailed in Note 10.

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

Development expenditure in MUSD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Norway	369.0	133.1	186.8	30.8
France	29.2	2.9	30.9	10.2
Netherlands	8.5	1.7	4.1	1.7
Indonesia	-0.4	-0.4	6.4	2.3
Russia	7.5	1.8	4.2	0.7
	413.8	**139.1**	232.4	45.7

During the reporting period, an amount of MUSD 369.0 of development expenditure was incurred in Norway, primarily on the Brynhild and Edvard Grieg field developments. In the comparative period, MUSD 186.8 was spent on the development of the Gaupe and Alvheim fields. In the reporting period, MUSD 29.2 was incurred in France, primarily on the Grandville field redevelopment.

Exploration and appraisal expenditure in MUSD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Norway	323.2	113.0	288.6	51.6
France	9.8	5.7	1.7	0.7
Indonesia	16.4	3.0	16.4	4.4
Russia	3.6	1.8	10.0	3.1
Malaysia	100.5	40.2	98.7	38.4
Congo (Brazzaville)	1.3	-0.5	19.0	11.4
Other	2.5	0.0	3.1	0.9
	457.3	**163.2**	437.5	110.5

During the reporting period, exploration and appraisal expenditure of MUSD 323.2 was incurred in Norway mainly on the appraisal drilling of the Johan Sverdrup field and exploration drilling of the Clapton prospect on PL440S, the Albert prospect on PL519, the Salinas prospect on PL533 and the Juksa well on PL490. In the comparative period, MUSD 288.6 was spent in Norway on the Johan Sverdrup field appraisal drilling and four exploration wells. MUSD 100.5 (MUSD 98.7) was spent in Malaysia primarily on drilling five wells and the acquisition of seismic data.

Tangible fixed assets amounted to MUSD 49.4 (MUSD 16.1) and represent office fixed assets and real estate, as well as the Ikdam FPSO which was consolidated for the first time in August 2012.

Financial assets amounted to MUSD 44.1 (MUSD 44.1) and are detailed in Note 11. Other shares and participations amounted to MUSD 20.0 (MUSD 17.8) and predominantly relate to the shares held in ShaMaran Petroleum which are reported at market value.

Current assets
Receivables and inventories amounted to MUSD 238.4 (MUSD 224.4) and are detailed in Note 12.

Inventories amounted to MUSD 18.7 (MUSD 31.6) and include both hydrocarbon inventories and well supplies. The reduction compared to 31 December 2011 is mainly due to the lifting of the Oudna field, Tunisia hydrocarbon inventory during the reporting period.

Underlift amounted to MUSD 26.4 (MUSD -) of which MUSD 24.5 related to the Norwegian producing fields, including the Gaupe field. At 31 December 2011, there was an overlift position of MUSD 7.7 shown under current liabilities which related to the Alvheim and Volund fields in Norway.

Prepaid expenses and accrued income amounted to MUSD 32.9 (MUSD 4.5) and includes prepaid insurance on the Edvard Grieg development project, Norway and 2013 Norwegian licence fees.

Cash and cash equivalents amounted to MUSD 97.4 (MUSD 73.6). Cash balances are held to meet operational and investment requirements.

Non-current liabilities
The non-current part of provisions amounted to MUSD 1,204.6 (MUSD 988.0) and is detailed in Note 13.

The provision for site restoration amounted to MUSD 190.5 (MUSD 119.3) and relates to future decommissioning obligations. The increase compared to 31 December 2011 mainly results from updated estimates for decommissioning costs and the use of a lower discount factor to calculate the present value of the decommissioning liabilities.

The provision for deferred taxes amounted to MUSD 942.2 (MUSD 803.5) and is arising 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 67.1 (MUSD 58.1).

Financial liabilities amounted to MUSD 384.2 (MUSD 204.5) and are detailed in Note 14. Bank loans amounted to MUSD 432.0 (MUSD 207.0) and relates to the outstanding loan under the Group's USD 2.5 billion revolving borrowing base facility. Capitalised financing fees amounted to MUSD 47.8 (MUSD 2.5) and relate to the new seven year USD 2.5 billion financing facility entered into in June 2012. The capitalised fees are being amortised over the expected life of the financing facility. The comparative amount relates to the balance of the capitalised financing fees for the previous financing facility which were fully expensed during the reporting period. Under reporting standards, the capitalised financing fees have been offset against the bank loan.

Other non-current liabilities amounted to MUSD 22.6 (MUSD 21.8) and mainly arises 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
Other current liabilities amounted to MUSD 423.5 (MUSD 390.6) and are detailed in Note 15.

Tax liabilities amounted to MUSD 170.0 (MUSD 240.1) of which MUSD 163.6 (MUSD 223.0) relates to Norway.

Joint venture creditors amounted to MUSD 213.9 (MUSD 88.4) 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 762.2 (MSEK -182.4) for the reporting period.

The operating income includes service income received from Group companies. The result includes general and administrative expenses of MSEK 84.5 (MSEK 206.1), intra-group interest expense of MSEK 31.3 (MSEK 25.5) and a dividend received from a subsidiary of MSEK 804.7 (MSEK -). The general and administrative expenses in the reporting period are impacted by the variation in the provision for the Group's LTIP. The high cost in the comparative period was a result of a significant increase in the Lundin Petroleum share price during 2011. The comparative period includes financial income of MSEK 6.5 for supporting certain financial obligations for ShaMaran Petroleum.

Pledged assets of MSEK 11,911.6 (MSEK 12,333.2) 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.)

RELATED PARTY TRANSACTIONS

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

The Group received MUSD 0.4 (MUSD 0.4) from ShaMaran Petroleum for the provision of office and other services and MUSD – (MUSD 0.9) for supporting certain financial obligations.

The Group paid MUSD 0.8 (MUSD 0.7) to other related parties in respect of aviation services received.

LIQUIDITY

Lundin Petroleum had a secured revolving borrowing base facility of MUSD 850 with a seven year term expiring in 2014. On 25 June 2012, Lundin Petroleum entered into a new seven year senior secured revolving borrowing base facility of USD 2.5 billion. The facility is with a group of 25 banks including many of the banks providing the USD 850 million facility. 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. For accounting purposes, the pledged amount at 31 December 2012 is MUSD 1,831.3 (MUSD 1,791.0) and is the accounting value of net assets of the Group companies whose shares are pledged.

The new facility has been completed to provide funding for Lundin Petroleum's ongoing exploration expenditure and development costs, particularly in Norway.

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 amounting to MUSD 75.4. 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 a tax dispute.

During the second quarter of 2012, Lundin Petroleum purchased 485,647 of its own shares at an average share price of SEK 128 per share.

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.

Under the authorisation of the Board granted at the AGM held on 10 May 2012, Lundin Petroleum purchased 485,647 of its own shares during the second quarter of 2012. As at 31 December 2012, Lundin Petroleum held 7,368,285 of its own shares.

The Board of directors will propose to the AGM that no dividend will be paid to the shareholders for the financial year 2012.

REMUNERATION
Lundin Petroleum's principles for remuneration are provided in the Company's 2011 Annual Report.

Unit Bonus Plan
In 2008, Lundin Petroleum implemented a LTIP scheme consisting of a Unit Bonus Plan which provides for an annual grant of units that will lead to a cash payment at vesting. The LTIP has a three year duration whereby the initial grant of units vests equally in three tranches: one third after one year; one third after two years; and the final third after three years. The cash payment is conditional upon the holder of the units remaining an employee of the Group at the time of payment. The share price for determining the cash payment at the end of each vesting period will be the five trading day average closing Lundin Petroleum share price prior to and following the actual vesting date.

An LTIP that follows the same principles as the 2008 LTIP has been implemented annually for employees other than Executive Management.

The number of units relating to the 2010, 2011 and 2012 Unit Bonus Plans outstanding as at 31 December 2012 were 209,162, 250,625 and 361,158 respectively.

Phantom Option Plan
At the AGM on 13 May 2009, the shareholders of Lundin Petroleum approved the implementation of an LTIP for Executive Management (being the President and Chief Executive Officer, the Chief Operating Officer, the Chief Financial Officer and the Senior Vice President Operations) consisting of a grant of phantom options exercisable after five years from the date of grant. The exercise of these options entitles the recipient to receive a cash payment based on the appreciation of the market value of the Lundin Petroleum share. Payment of the award under these phantom options will occur in two equal installments: (i) first on the date immediately following the fifth anniversary of the date of grant and (ii) second on the date which is one year following the date of the first payment.

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. The recipients will be entitled to receive a cash payment equal to the average closing price of the Company's shares during the fifth year following grant, less the exercise price, multiplied by the number of phantom options. The participants of the phantom option plan are not entitled to receive new awards under the Unit Bonus Plan whilst the phantom options are still outstanding.

Lundin Petroleum purchased 6,882,638 of its own shares up to 31 December 2010 at an average cost of SEK 46.51 per share to mitigate against the exposure of the LTIP. The Lundin Petroleum share price at 31 December 2012 was SEK 149.50. The provision for LTIP amounted to MUSD 64.0 including social charges as at 31 December 2012 and the market value of these shares held at 31 December 2012 was MUSD 158.2. 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 (1995:1554). The accounting policies adopted are consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2011.

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 (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 2011 Annual Report.

Derivative financial instruments

During the second quarter of 2012, the Group entered into currency hedging contracts fixing the rate of exchange from USD into NOK to meet NOK operational and tax requirements as summarised in the table below. Under IAS 39, subject to hedge effectiveness testing, these hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. At 31 December 2012, a current asset has been recognised amounting to MUSD 9.1 (MUSD -) representing the short-term portion of the fair value of the outstanding currency hedging contracts.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 1,580.7	MUSD 261.6	NOK 6.04: 1 USD	1 Jun 2012 – 20 Dec 2012
MNOK 670.7	MUSD 110.4	NOK 6.07: 1 USD	2 Jan 2013 – 20 Dec 2013

EXCHANGE RATES

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

	31 Dec 2012		31 Dec 2011	
	Average	Period end	Average	Period end
1 USD equals NOK	5.8148	5.5639	5.5998	5.9927
1 USD equals Euro	0.7778	0.7579	0.7185	0.7729
1 USD equals Rouble	31.0546	30.5665	29.3738	32.2784
1 USD equals SEK	6.7725	6.5045	6.4867	6.8877

CONSOLIDATED INCOME STATEMENT IN SUMMARY

Expressed in TUSD	Note	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Operating income					
Net sales of oil and gas	1	1,319,490	337,258	1,257,691	318,810
Other operating income		25,652	5,342	11,824	4,193
		1,345,142	**342,600**	1,269,515	323,003
Cost of sales					
Production costs	2	-172,474	-48,243	-193,104	-46,935
Depletion and decommissioning costs	3	-191,444	-50,051	-165,138	-43,757
Exploration costs	4	-168,480	-134,920	-140,027	-59,800
Impairment costs of oil and gas properties	5	-237,490	-237,490	–	–
Gross profit		**575,254**	**-128,104**	771,246	172,511
General, administration and depreciation expenses		-31,722	-5,336	-67,022	-31,903
Operating profit	6	**543,532**	**-133,440**	704,224	140,608
Result from financial investments					
Financial income	7	27,241	10,486	46,455	7,305
Financial expenses	8	-48,522	-10,428	-21,022	-4,790
		-21,281	**58**	25,433	2,515
Profit before tax		**522,251**	**-133,382**	729,657	143,123
Income tax expense	9	-418,401	80,639	-574,413	-157,158
Net result		**103,850**	**-52,743**	155,244	-14,035
Net result attributable to the shareholders of the Parent Company:		108,161	-51,545	160,137	-12,500
Net result attributable to non-controlling interest:		-4,311	-1,198	-4,893	-1,535
Net result		**103,850**	**-55,743**	155,244	-14,035
Earnings per share – USD[1]		0.35	-0.16	0.51	-0.05
Diluted earnings per share – USD[1]		0.35	-0.16	0.51	-0.05

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME IN SUMMARY

Expressed in TUSD	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Net result	**103,850**	**-52,743**	155,244	-14,035
Other comprehensive income				
Exchange differences foreign operations	61,661	25,482	-37,525	-25,193
Cash flow hedges	9,222	-4,779	6,971	1,708
Available-for-sale financial assets	16,053	-2,984	-50,210	-1,583
Income tax relating to other comprehensive income	-2,306	1,194	-1,743	-427
Other comprehensive income, net of tax	84,630	18,913	-82,507	-25,495
Total comprehensive income	**188,480**	**-33,830**	72,737	-39,530
Total comprehensive income attributable to:				
Shareholders of the Parent Company	190,233	-33,362	80,466	-37,732
Non-controlling interest	-1,753	-468	-7,729	-1,798
	188,480	-33,830	72,737	-39,530

CONSOLIDATED BALANCE SHEET IN SUMMARY

Expressed in TUSD	Note	**31 December 2012**	31 December 2011
ASSETS			
Non-current assets			
Oil and gas properties	10	2,864,395	2,329,270
Other tangible assets		49,418	16,084
Financial assets	11	44,105	44,080
Total non-current assets		**2,957,918**	2,389,434
Current assets			
Receivables and inventories	12	238,383	224,407
Cash and cash equivalents		97,425	73,597
Total current assets		**335,808**	298,004
TOTAL ASSETS		**3,293,726**	2,687,438
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,182,405	1,000,882
Non-controlling interest		67,648	69,424
Total equity		**1,250,053**	1,070,306
Non-current liabilities			
Provisions	13	1,204,625	987,993
Financial liabilities	14	384,188	204,494
Other non-current liabilities		22,556	21,830
Total non-current liabilities		**1,611,369**	1,214,317
Current liabilities			
Other current liabilities	15	423,479	390,600
Provisions	13	8,825	12,215
Total current liabilities		**432,304**	402,815
TOTAL EQUITY AND LIABILITIES		**3,293,726**	2,687,438

CONSOLIDATED STATEMENT OF CASH FLOW IN SUMMARY

Expressed in TUSD	Note	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Cash flow from operations					
Net result		103,850	-52,743	155,244	-14,035
Adjustments for non-cash related items	16	1,056,898	350,574	915,174	291,974
Gain on sale of asset		-1,117	-1,117	–	–
Interest received		3,489	2,234	1,457	41
Interest paid		-8,871	-3,252	-1,597	2,335
Income taxes paid		-428,842	-121,595	-183,870	-119,547
Changes in working capital		93,547	23,636	10,528	-26,957
Total cash flow from operations		**818,954**	**197,737**	896,936	133,811
Cash flow from investments					
Investment in oil and gas properties		-919,356	-352,182	-670,032	-156,305
Investment in office equipment and other assets		-9,702	-4,906	-3,786	-673
Investment in subsidiaries		-11,000	–	–	–
Change in other financial fixed assets		–	–	1,908	12,168
Proceeds from sale of other shares and participations		–	–	53,938	–
Decommissioning costs paid		-18,550	-9,816	–	–
Other payments		-3,188	-302	-1,168	-293
Total cash flow from investments		**-961,796**	**-367,206**	-619,140	-145,103
Cash flow from financing					
Changes in long-term liabilities		225,726	111,169	-252,238	-13,616
Financing fees paid		-49,225	-445	–	–
Purchase of own shares		-8,710	–	–	–
Dividend to non-controlling interest paid		-23	–	-212	–
Total cash flow from financing		**167,768**	**110,724**	-252,450	-13,616
Change in cash and cash equivalents		24,926	-58,745	25,346	-24,908
Cash and cash equivalents at the beginning of the period		73,597	156,918	48,703	98,075
Cash acquired on consolidation of subsidiary		815	–	–	–
Currency exchange difference in cash and cash equivalents		-1,913	-748	-452	430
Cash and cash equivalents at the end of the period		**97,425**	**97,425**	73,597	73,597

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY IN SUMMARY

Expressed in TUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Net result	Non-controlling interest	Total equity
Balance at 1 January 2011	**463**	**417,430**	**-9,352**	**511,875**	**77,365**	**997,781**
Transfer of prior year net result	–	–	511,875	-511,875	–	–
Total comprehensive income	**–**	**-79,671**	**–**	**160,137**	**-7,729**	**72,737**
Transactions with owners						
Distributions	–	–	–	–	-212	-212
Total transactions with owners	**–**	**–**	**–**	**–**	**-212**	**-212**
Balance at 31 December 2011	**463**	**337,759**	**502,523**	**160,137**	**69,424**	**1,070,306**
Transfer of prior year net result	–	–	160,137	-160,137	–	–
Total comprehensive income	**–**	**82,072**	**–**	**108,161**	**-1,753**	**188,480**
Transactions with owners						
Distributions	–	–	–	–	-23	-23
Purchase of own shares	–	-8,710	–	–	–	-8,710
Total transactions with owners	–	**-8,710**	–	–	**-23**	**-8,733**
Balance at 31 December 2012	**463**	**411,121**	**662,660**	**108,161**	**67,648**	**1,250,053**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Net sales of oil and gas, TUSD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Net sales of:				
Crude oil				
Norway	953,432	235,485	911,072	236,431
France	114,974	36,763	127,789	31,359
Netherlands	170	53	231	57
Russia	75,806	17,806	79,515	19,078
Tunisia	24,597	–	24,795	–
	1,168,979	**290,107**	1,143,402	286,925
Condensate				
Norway	2,312	2,312	–	–
Netherlands	999	269	1,314	343
	3,311	**2,581**	1,314	343
Gas				
Norway	94,851	30,579	57,909	16,329
Netherlands	41,385	10,393	42,496	11,448
Indonesia	10,964	3,598	12,570	3,765
	147,200	**44,570**	112,975	31,542
	1,319,490	**337,258**	1,257,691	318,810

Note 2. Production costs, TUSD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Cost of operations	105,612	29,244	102,476	28,338
Tariff and transportation expenses	29,684	8,681	22,863	5,228
Direct production taxes	51,328	12,315	52,390	12,843
Change in inventory/lifting position	-15,918	-1,997	13,129	-17
Other	1,768	–	2,246	543
	172,474	**48,243**	193,104	46,935

Note 3. Depletion and decommissioning costs, TUSD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Depletion charges				
Norway	154,140	39,625	130,011	34,622
France	11,668	2,954	12,174	3,056
Netherlands	10,437	2,499	11,939	2,985
Indonesia	5,612	2,225	6,250	1,932
Russia	4,320	1,023	4,764	1,162
	186,177	**48,326**	165,138	43,757
Decommissioning costs				
Tunisia	5,267	1,725	–	–
	5,267	**1,725**	–	–
	191,444	**50,051**	165,138	43,757

Note 4. Exploration costs, TUSD	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Norway	103,052	89,371	74,060	7,333
Indonesia	7,432	332	967	401
Malaysia	46,683	37,502	11,015	–
Congo (Brazzaville)	1,298	-456	51,263	51,263
Other	10,015	8,171	2,722	803
	168,480	**134,920**	140,027	59,800

Note 5. Impairment costs of oil and gas properties, TUSD	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Norway	205,835	205,835	–	–
Russia	31,655	31,655	–	–
	237,490	**237,490**	**–**	**–**

Note 6. Operating profit, TUSD	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Operating profit				
Norway	558,646	-80,566	703,711	196,175
France	70,429	18,222	85,334	19,888
Netherlands	29,908	4,370	18,868	4,786
Indonesia	-7,511	-23	168	-267
Russia	-26,304	-31,077	7,715	1,191
Tunisia	-4,297	-2,290	13,476	-197
Malaysia	-47,554	-36,753	-11,010	–
Congo (Brazzaville)	-1,309	445	-51,273	-51,273
Other	-28,476	-5,768	-62,765	-29,695
	543,532	**-133,440**	704,224	140,608

Note 7. Financial income, TUSD	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Interest income	5,050	2,545	4,138	815
Foreign currency exchange gain, net	6,154	5,473	8,945	6,291
Guarantee fees	233	233	998	294
Gain on sale of shares	–	–	29,974	–
Gain on consolidation of subsidiary	13,409	–	–	–
Other	2,395	2,235	2,400	-95
	27,241	**10,486**	46,455	7,305

Note 8. Financial expenses, TUSD	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Interest expense	6,819	2,029	5,390	1,093
Foreign currency exchange loss, net	–	–	–	–
Result on interest rate hedge settlement	198	–	6,995	1,761
Unwinding of site restoration discount	5,073	1,311	4,494	1,091
Amortisation of deferred financing fees	6,634	2,050	2,181	459
Loan facility commitment fees	10,315	4,667	1,005	205
Impairment of other shares	18,631	–	–	–
Other	852	371	957	180
	48,522	**10,428**	21,022	4,790

Note 9. Income tax expense, TUSD	1 Jan 2012-31 Dec 2012 12 months	1 Oct 2012-31 Dec 2012 3 months	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Current tax	341,301	56,947	400,210	186,701
Deferred tax	77,100	-137,586	174,203	-29,543
	418,401	**-80,639**	574,413	157,158

Note 10. Oil and gas properties, TUSD	**31 Dec 2012**	31 Dec 2011
Norway	1,702,319	1,269,746
France	216,812	172,467
Netherlands	65,796	43,739
Indonesia	96,878	93,610
Russia	599,221	615,015
Malaysia	183,369	129,830
Other	–	4,863
	2,864,395	2,329,270

Note 11. Financial assets, TUSD	**31 Dec 2012**	31 Dec 2011
Other shares and participations	19,983	17,775
Bonds	9,526	9,588
Deferred tax	13,270	15,345
Other	1,326	1,372
	44,105	44,080

Note 12. Receivables and inventories, TUSD	**31 Dec 2012**	31 Dec 2011
Inventories	18,700	31,589
Trade receivables	125,905	144,954
Underlift	26,439	1,851
Corporate tax	3,986	–
Joint venture debtors	11,539	20,252
Derivative instruments	9,056	–
Prepaid expenses and accrued income	32,906	4,522
Other	9,852	21,239
	238,383	224,407

Note 13. Provisions, TUSD	**31 Dec 2012**	31 Dec 2011
Non-current:		
Site restoration	190,470	119,341
Deferred tax	942,235	803,493
Long-term incentive plan	67,135	58,079
Pension	1,510	1,460
Other	3,275	5,620
	1,204,625	987,993
Current:		
Long-term incentive plan	8,825	12,215
	8,825	12,215
	1,213,450	1,000,208

Note 14. Financial liabilities, TUSD	**31 Dec 2012**	31 Dec 2011
Bank loans	432,000	207,000
Capitalised financing fees	-47,812	-2,506
	384,188	204,494

Note 15. Other current liabilities, TUSD	**31 Dec 2012**	31 Dec 2011
Trade payables	15,718	16,546
Overlift	490	7,670
Tax liabilities	170,007	240,052
Accrued expenses and deferred income	8,337	16,227
Joint venture creditors	213,944	88,417
Derivative instruments	–	168
Other	14,983	21,520
	423,479	390,600

Note 16. Adjustment for non-cash related items, TUSD	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Exploration costs	168,480	134,920	140,027	59,800
Depletion, depreciation and amortisation	189,293	49,086	167,812	44,344
Current tax	341,301	56,947	400,210	186,701
Deferred tax	77,100	-137,586	174,203	-29,543
Gain on sale of shares	–	–	-29,974	–
Impairment of oil and gas properties	237,490	237,490	–	–
Impairment of other shares	18,631	–	–	–
Long-term incentive plan	12,988	-1,210	63,443	35,179
Other	11,615	10,927	-547	-4,507
	1,056,898	**350,574**	915,174	291,974

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in TSEK	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Operating income				
Other operating income	70,956	26,914	42,644	13,599
Gross profit	**70,956**	**26,914**	42,644	13,599
General and administration expenses	-84,533	-7,005	-206,108	-94,157
Operating loss	**-13,577**	**19,909**	-163,464	-80,558
Result from financial investments				
Financial income	807,074	806,123	6,560	1,877
Financial expenses	-31,266	-5,513	-25,495	-7,181
	775,808	**800,610**	-18,935	-5,304
Profit before tax	**762,231**	**820,519**	-182,399	-85,862
Income tax expense	–	–	–	–
Net result	**762,231**	**820,519**	-182,399	-85,862

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in TSEK	**1 Jan 2012-31 Dec 2012 12 months**	**1 Oct 2012-31 Dec 2012 3 months**	1 Jan 2011-31 Dec 2011 12 months	1 Oct 2011-31 Dec 2011 3 months
Net result	762,231	820,519	-182,399	-85,862
Other comprehensive income	–	–	–	–
Total comprehensive income	**762,231**	**820,519**	-182,399	-85,862
Total comprehensive income attributable to:				
Shareholders of the Parent Company	762,231	820,519	-182,399	-85,862
	762,231	**820,519**	-182,399	-85,862

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in TSEK	**31 December 2012**	31 December 2011
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871,847	7,871,947
Receivables from group companies	21,370	–
Total non-current assets	**7,893,217**	7,871,947
Current assets		
Receivables	20,698	8,954
Cash and cash equivalents	1,080	3,849
Total current assets	**21,778**	12,803
TOTAL ASSETS	**7,914,995**	7,884,750
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,869,783	7,169,977
Non-current liabilities		
Provisions	36,402	36,403
Payables to Group companies	–	673,988
Total non-current liabilities	**36,402**	710,391
Current liabilities		
Current liabilities	8,810	4,382
Total current liabilities	**8,810**	4,382
TOTAL EQUITY AND LIABILITIES	**7,914,995**	7,884,750
Pledged assets	11,911,649	12,333,233

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in TSEK	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Cash flow from operations				
Net result	762,231	820,519	-182,399	-85,862
Adjustment for non-cash related items	-725,237	-810,779	207,811	94,494
Changes in working capital	-6,383	1,978	-12,492	-12,661
Total cash flow from operations	**30,611**	**11,718**	12,920	-4,029
Cash flow from investments				
Change in long term financial fixed assets	100	100	–	–
Total Cash flow from investments	**100**	**100**	–	–
Cash flow from financing				
Change in long-term liabilities	29,129	-17,717	-15,702	7,131
Purchase of own shares	-62,425	–	–	–
Total cash flow from financing	**-33,296**	**-17,717**	-15,702	7,131
Change in cash and cash equivalents	-2,585	-5,899	-2,782	3,102
Cash and cash equivalents at the beginning of the period	3,849	6,985	6,735	894
Currency exchange difference in cash and cash equivalents	-184	-6	-104	-147
Cash and cash equivalents at the end of the period	**1,080**	**1,080**	3,849	3,849

PARENT COMPANY STATEMENT OF CHANGES IN EQUITY IN SUMMARY

	Restricted equity		Unrestricted equity			
Expressed in TSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Net result	Total equity
Balance at 1 January 2011	**3,179**	**861,306**	**2,551,805**	**–**	**3,936,086**	**7,352,376**
Transfer of prior year net result	–	–	–	3,936,086	-3,936,086	–
Total comprehensive income	**–**	**–**	**–**	**–**	**-182,399**	**-182,399**
Balance at 31 December 2011	**3,179**	**861,306**	**2,551,805**	**3,936,086**	**-182,399**	**7,169,977**
Transfer of prior year net result	–	–	–	-182,399	182,399	–
Total comprehensive income	**–**	**–**	**–**	**–**	**762,231**	**762,231**
Transactions with owners						
Purchase of own shares	–	–	-62,425	–	–	-62,425
Total transactions with owners	**–**	**–**	**-62,425**	**–**	**–**	**-62,425**
Balance at 31 December 2012	**3,179**	**861,306**	**2,489,380**	**3,753,687**	**762,231**	**7,869,783**

KEY FINANCIAL DATA

Financial data (TUSD)	**1 Jan 2012- 31 Dec 2012 12 months**	**1 Oct 2012- 31 Dec 2012 3 months**	1 Jan 2011- 31 Dec 2011 12 months	1 Oct 2011- 31 Dec 2011 3 months
Operating income	1,345,142	342,600	1,269,515	323,003
EBITDA	1,144,061	289,779	1,012,063	244,752
Net result	103,850	-52,743	155,244	-14,035
Operating cash flow	831,366	237,409	676,201	89,367
Data per share (USD)				
Shareholders' equity per share	3.81	3.81	3.22	3.22
Operating cash flow per share	2.68	0.77	2.17	0.28
Cash flow from operations per share	2.64	0.64	2.88	0.43
Earnings per share	0.35	-0.16	0.51	-0.05
Earnings per share fully diluted	0.35	-0.16	0.51	-0.05
EBITDA per share fully diluted	3.68	0.93	3.25	0.78
Dividend per share	–	–	–	–
Number of shares issued at period end	317,910,580	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	310,542,295	310,542,295	311,027,942	311,027,942
Weighted average number of shares for the period	310,735,227	310,542,295	311,027,942	311,027,942
Weighted average number of shares for the period (fully diluted)	310,735,227	310,542,295	311,027,942	311,027,942
Share price				
Quoted price at period end (SEK)	149.50	149.50	169.20	169.20
Quoted price at period end (CAD)	22.87	22.87	24.54	24.54
Key ratios				
Return on equity (%)	9	-4	15	-1
Return on capital employed (%)	35	-10	53	12
Net debt/equity ratio (%)	30	30	15	15
Equity ratio (%)	38	38	40	40
Share of risk capital (%)	66	66	69	69
Interest coverage ratio	75	-67	59	49
Operating cash flow/interest ratio	119	117	55	31
Yield	–	–	–	–

KEY RATIO DEFINITIONS

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

Operating cash flow per share: Operating income 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 of outstanding warrants.

EBITDA per share fully diluted: EBITDA divided by the weighted average number of shares for the period after considering the dilution effect of outstanding warrants. EBITDA is defined as operating profit before depletion of oil and gas properties, exploration costs, impairment costs, depreciation of other assets and gain on sale of assets.

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: Operating income 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 February 2013

Ian H. Lundin Chairman	C. Ashley Heppenstall President and CEO	William A. Rand
Asbjørn Larsen	Lukas H. Lundin	Magnus Unger
	Kristin Færøvik	

Financial information

The Company will publish the following reports:

- The three month report (January – March 2013) will be published on 7 May 2013.
- 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 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 2011, 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 and Resources” 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.