Lundin Petroleum

Q1

Report for the THREE MONTHS ended 31 March 2016

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Three months ended 31 March 2016 (31 March 2015)

- Production of 62.4 Mboepd (25.8 Mboepd)
- Revenue of MUSD 191.3 (MUSD 121.3)
- EBITDA of MUSD 124.9 (MUSD 86.0)
- Operating cash flow of MUSD 162.6 (MUSD 155.7)
- Net result of MUSD 114.3 (MUSD -230.9) including a net foreign exchange gain of MUSD 158.6
- Net debt of MUSD 4,172 (31 December 2015: MUSD 3,786)
- Record production level achieved following the Edvard Grieg field start-up in late 2015.
- Signing of a new reserve-base lending facility of USD 5 billion with an initial firm commitment of USD 4,303 million subsequently increased by USD 185 million to USD 4,488 million.

	1 Jan 2016– 31 Mar 2016 3 months	1 Jan 2015 — 31 Mar 2015 3 months	1 Jan 2015 — 31 Dec 2015 12 months
Production in Mboepd	**62.4**	25.8	32.3
Revenue in MUSD	**191.3**	121.3	569.3
Net result in MUSD	**114.3**	-230.9	-866.3
Net result attributable to shareholders of the Parent Company in MUSD	**115.4**	-229.9	-861.7
Earnings/share in USD[1]	**0.37**	-0.74	-2.79
Earnings/share fully diluted in USD[1]	**0.37**	-0.74	-2.79
EBITDA in MUSD	**124.9**	86.0	384.7
Operating cash flow in MUSD	**162.6**	155.7	699.6

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

Definitions

An extensive list of definitions can be found on www.lundin-petroleum.com under the heading “Definitions”.

Abbreviations

EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
CAD	Canadian dollar
CHF	Swiss franc
EUR	Euro
NOK	Norwegian krona
RUR	Russian rouble
SEK	Swedish krona
USD	US dollar
TSEK	Thousand SEK
TUSD	Thousand USD
MSEK	Million SEK
MUSD	Million USD

Oil related terms and measurements

boe	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Mbbl	Thousand barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
Mcf	Thousand cubic feet

Letter to Shareholders

Dear fellow Shareholders,

The world has presented us with a challenging market environment since I assumed the position as CEO of Lundin Petroleum in October 2015. This was particularly true during the first quarter of 2016 when the oil price averaged below USD 35 per barrel, with a low of USD 26 per barrel reached in late January, a level not witnessed since November 2003. It has been truly a challenging period but at the same time a very rewarding one. Whilst we have continued to witness extreme volatility in oil prices, I believe a rebalancing of supply and demand is likely in the second half of 2016 as a consequence of significant underinvestment and project deferrals in our industry both onshore and offshore.

Edvard Grieg acquisition

During challenging periods successful companies are those which can embrace the situation and see it as a time of opportunity. This is exactly what Lundin Petroleum managed to achieve when we approached Statoil with a proposal to acquire their 15 percent interest in the Edvard Grieg field in exchange for newly issued shares in the Company. For Lundin Petroleum it increases our exposure to a world class asset, adding significant reserves, production and cash flow in the heart of our core area in Norway. For Statoil, it further increases their indirect exposure to Johan Sverdrup and Edvard Grieg and gives them the ability to equity account for their significant shareholding in the Company, adding additional reserves and production. Acquiring additional exposure in Edvard Grieg at the bottom of the industry cycle will, in my view, lead to Lundin Petroleum emerging stronger than ever as an independent company and continue to build upon the transformational growth already well under way.

In parallel, we have continued to focus on our four main objectives: maximising our operational efficiency, maintaining a robust balance sheet and strong access to liquidity, playing a proactive role towards the development of Johan Sverdrup and continuing to actively follow our organic growth strategy.

Operational efficiency

In terms of operational efficiency we have delivered a strong first quarter performance with high average uptime across all our operations resulting in a record high first quarter average production rate for the Company of 62,400 boepd which is eight percent ahead of our mid-point capital market day guidance. This was driven by a combination of excellent facilities uptime performance at Edvard Grieg in excess of 96 percent as well as excellent well productivity much beyond our initial PDO estimates. This is simply a remarkable achievement by our operational team in Norway, executed with the highest level of health and safety performance. Furthermore, we continue to focus on capital efficiency by taking advantage of the current market downturn. We achieved a record low cost of operations per barrel of USD 7.45 for the first quarter of this year.

Strong access to liquidity

On the financial side a major milestone was achieved when announcing in February the signing of a new reserve-base lending facility of USD 5 billion with an initial firm commitment of USD 4,303 million. Subsequently, commitment levels have been increased by USD 185 million to USD 4,488 million from both existing and new banks. This is an achievement at a time of extreme volatility in the banking markets. It is also a testimony to the very high quality assets we have such as the Johan Sverdrup and the Edvard Grieg fields. Those are simply unique and highly prized assets.

Lundin Petroleum is in strong health with a solid production base that will continue to grow and with an operating cost below USD 10 per barrel, combined with strong access to liquidity to withstand the cur rent low oil price environment. This puts us in an enviable position.

Johan Sverdrup development

I am pleased to also report that the Johan Sverdrup development is progressing according to plan. This year a major milestone will be the concept selection of Phase 2 which will take place towards year end. We have recently completed a debottleneck study for Phase 1 of the project which concludes a potential of an increased processing capacity from the previously guided range of 315,000 to 380,000 bopd up to a revised 440,000 bopd. Phase 1 first oil remains on schedule for the end of 2019. I am confident that we will see further project cost reductions, particularly at the time of Phase 2 concept selection. We will continue to work proactively together with Statoil as a partner with the ultimate objective to further enhance the value of Johan Sverdrup, a world class asset.

Letter to Shareholders

Continuing our organic growth strategy
Our organic growth strategy continues with a particular focus on the southern Barents Sea where we will resume drilling activities in the second half of this year, with two exploration wells and one appraisal well on the Alta discovery. In addition, studies are ongoing to establish commerciality on both our Luno II and Alta and Gotha discoveries. During this last quarter we were also able to secure the Leiv Eiriksson semi-submersible rig for a very competitive day rate which we will be able to extend at our option should we decide to continue our drilling activities into next year.

Looking back, whilst in our last six months we have had disappointing exploration results, I remain confident in our ability to continue to find new resources within our core exploration areas. We have a great team, a clear strategy and some very exciting acreage positions. We will continue to generate significant shareholder value through our ability to find new resources at low finding costs per barrel.

There is no question in my mind that this last quarter has been a challenging and at the same time a remarkable one, in which we have laid solid foundations to deliver significant sustainable value growth as we also move towards a more favourable oil market environment. It is during such challenging times that the quality of your team is best recognised and there is no question in my mind that we have absolutely the best team one can wish for. Their enthusiasm, entrepreneurship and hardworking culture will position Lundin Petroleum from this downturn as a Company that is stronger than ever.

To you, fellow shareholders, the Board and the whole team at Lundin Petroleum, I am very grateful for your continued support.

Exciting times ahead!

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 11 May 2016

Financial Report for the Three Months Ended 31 March 2016

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon two core areas, Norway and Malaysia, as well as assets in France, the Netherlands and Russia. Norway continues to represent the majority of Lundin Petroleum's operational activities with production for the three month period ending 31 March 2016 (reporting period) accounting for 77 percent of total production and with 95 percent of Lundin Petroleum's total reserves as at the end of 2015.

Reserves and Resources

Lundin Petroleum has 685 million barrels of oil equivalent (MMboe) of proven plus probable reserves as at 31 December 2015 as certified by an independent third party. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. The best estimate contingent resources net to Lundin Petroleum amount to 386 MMboe as at 31 December 2015.

Production

Production for the reporting period amounted to 62.4 thousand barrels of oil equivalent per day (Mboepd) (compared to 25.8 Mboepd for the same period in 2015) and was comprised as follows:

Production in Mboepd	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Crude oil			
Norway	43.0	17.3	18.6
France	2.6	2.9	2.7
Malaysia	8.5	–	5.5
Total crude oil production	**54.1**	20.2	26.8
Gas			
Norway	4.9	2.1	2.1
Netherlands	1.7	1.8	1.8
Indonesia	1.7	1.7	1.6
Total gas production	**8.3**	5.6	5.5
Total production			
Quantity in Mboe	**5,674.3**	2,322.4	11,790.3
Quantity in Mboepd	**62.4**	25.8	32.3

Norway

Production

Production in Mboepd	WI [1]	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Edvard Grieg	50%	30.2	–	1.4
Alvheim	15%	8.8	8.6	7.8
Volund	35%	3.5	5.8	4.9
Bøyla	15%	2.1	1.9	2.1
Brynhild	90%	3.1	3.1	4.2
Gaupe	40%	0.2	–	0.3
		47.9	19.4	20.7

[1] Lundin Petroleum's working interest (WI)

The Edvard Grieg field commenced production on 28 November 2015 with average net production for the reporting period ahead of forecast at 30,200 barrels of oil equivalent per day (boepd). The field initially started production from one well with the second and third production wells commencing production in December 2015 and January 2016 respectively. The production capacity from the first three wells has exceeded expectations and the reservoir pressure depletion has been more favourable than anticipated, which is encouraging with respect to the field's future performance. In accordance with the reservoir management plan, the production levels will be held below the well potential until sufficient water injection wells become available to balance production levels with available injection.

The facilities uptime has also been exceptional with an average uptime of 96 percent for the reporting period. The average facilities uptime during 2016 is expected to be lower than has been achieved to date as certain downtime is expected in relation to remaining commissioning activities and the tie-in of the Ivar Aasen field during the fourth quarter of 2016. The first water injection well is currently drilling and is expected to be completed in the second quarter 2016. That will be followed by the second water injection well and with the fourth production well expected to be drilled and put into production during the second half of 2016 when the field is forecast to achieve its gross plateau production of 100,000 boepd. A total of 14 development wells are scheduled to be drilled on Edvard Grieg with drilling operations expected to continue into 2018. The total operating cost for the Edvard Grieg field was USD 9.25 per barrel during the reporting period and is expected to be below USD 9 per barrel for the year.

In April 2016 Lundin Petroleum announced that it had acquired an additional 15 percent working interest in the Edvard Grieg field from Statoil ASA. The effective date of the transaction is 1 January 2016 and as a result of this transaction Lundin Petroleum has increased its reserves by 31 MMboe (1 January 2016). The additional production from this transaction will be accounted for from the date of completion. Assuming a completion date of 1 July 2016 the additional full year 2016 production from this transaction will be 5,000 boepd net to Lundin Petroleum thus changing Lundin Petroleum full year production guidance from between 60,000 and 70,000 boepd to between 65,000 and 75,000 boepd.

Production from the Greater Alvheim area during the reporting period was in line with forecast. Utilisation of the Alvheim FPSO processing capacity is optimised within the constraints of the commercial arrangements to maximise production across all the fields in the Greater Alvheim area resulting in some production changes at a field level. The Alvheim FPSO uptime was better than forecast during the reporting period at 99.3 percent. The total operating cost for the Greater Alvheim area was just below USD 5 per barrel during the reporting period and is forecast to be just over USD 6 per barrel for the year.

Net production from the Alvheim field during the reporting period was marginally below forecast at 8,800 boepd. Whilst the reservoir performance remains excellent the production levels have been optimised within the processing constraints of the FPSO. Infill development drilling on Alvheim is continuing with the drilling of the A5 well, a 3-branch production well, having been completed in early 2016 with tie-in operations ongoing for an estimated production start-up around mid-2016. The drilling of the Viper and Kobra development wells commenced in February 2016 and is currently ongoing with expected start-up of these two wells towards the end of 2016. The Alvheim partnership signed a new rig contract to commence in December 2016 with the objective of drilling further infill development wells and a near-field exploration well in the Alvheim area.

The Volund field net production during the reporting period was slightly below forecast at 3,500 boepd. Further infill opportunities have been identified on the Volund field and at least two further infill wells are planned to be drilled with drilling expected to commence in late 2016. The planned infill drilling on Volund has led to 3 MMboe of net incremental reserves being booked as at 31 December 2015.

The Bøyla field net production during the reporting period was ahead of forecast at 2,100 boepd due to good reservoir performance with lower water cut in the wells than expected.

The total operating cost for the Greater Alvheim area was just below USD 5 per barrel during the reporting period and is forecast to be just over USD 6 per barrel for the year.

Net production from the Brynhild field during the reporting period was better than forecast at 3,100 boepd due to excellent performance from the Haewene Brim FPSO which achieved an uptime of over 98 percent up to a planned shut-in of the FPSO in mid-March 2016. The FPSO remained shut-in for approximately one month for planned maintenance work and the field re-commenced production in mid-April 2016. Water injection from one well commenced in January 2016 and during the reporting period one producing well was converted to a water injection well so that the field now is receiving pressure support from two water injectors.

Despite no remaining reserves being attributed to the Gaupe field, the field is producing intermittently subject to favourable economic conditions and achieved net production of 200 boepd during the reporting period.

Development

Licence	Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
Ivar Aasen Unit	Ivar Aasen	1.385%	Det norske	May 2013	183 million boe	Q4 2016	65 Mboepd
Johan Sverdrup Unit	Johan Sverdrup	22.60%	Statoil	August 2015	1.65 – 3.0 billion boe	Late 2019	550 – 650 Mboepd

Ivar Aasen

Ivar Aasen is being developed with a steel jacket platform with the topside facilities consisting of a living quarter and processing facilities with oil, gas and water separation and onward export to the Edvard Grieg platform for final processing and pipeline export. The steel jacket was successfully installed in June 2015 and the pipelines installation between Ivar Aasen and Edvard Grieg was completed during the third quarter of 2015. The topside construction is 98 percent complete as of March 2016 with mechanical completion expected during the first half of 2016. The topsides installation is scheduled during the summer of 2016. Ivar Aasen is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

The Johan Sverdrup project is progressing on schedule with a majority of contracts now awarded, resulting in estimated total project costs being reduced compared to the original estimates. Phase 1 construction work commenced in 2015.

Construction of two steel jackets has commenced at the Kvæaerner yard on the west coast of Norway and of one jacket at the Dragados yard in Spain. Construction of the drilling platform and living quarters topsides has also begun. In addition civil engineering works is underway on the onshore power system at Haugsneset in Norway. The pre-drilling of development wells commenced in March 2016 with the first development well being completed ahead of schedule.

At the time of submitting the Phase 1 PDO in February 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). With most of the major contracts now awarded, the latest cost estimate has been reduced to NOK 108.5 billion (nominal), a reduction of approximately 12 percent. The Phase 1 development is scheduled to start production in late 2019. The original gross production capacity for Phase 1 was estimated at 380,000 bopd. However, debottlenecking measures have concluded that the design processing capacity for Phase 1 will increase from the range of between 315,000 and 380,000 bopd up to 440,000 bopd with gas processing capacity in addition. It is anticipated that 35 production and injection wells will be drilled to support Phase 1 production, of which 17 wells will be drilled prior to first oil with a semisubmersible rig to facilitate Phase 1 plateau production.

The PDO for Phase 1 involves a field centre, consisting of one processing platform, one riser platform, one wellhead platform with drilling facilities and one living quarters platform. The platforms will be installed on steel jackets in 120 metres of water and will be bridge-linked. A majority of the contracts have already been awarded for the development of Phase 1. Notably, all four topside contracts have been awarded, with EPC type contracts being awarded to Aibel (drilling platform) and Kværner/KBR (living quarters and utilities) whilst a fabrication contract has been awarded to Samsung Heavy Industries (riser platform and processing platform) with Aker Solutions being contracted for the procurement and engineering of the riser and processing platforms. The contract for the heavy lift installations for three of the topsides has been awarded to Allseas and contracts for the construction of three of the steel jackets for the riser, drilling and processing platforms have been awarded to Kværner, whilst the contract for the jacket for the utility and living quarter platform has been awarded to Dragados Offshore. Odfjell Drilling has been awarded contracts for drilling of the wells.

The PDO for Phase 1 also outlines certain concepts for the full field development involving an expected full field gross plateau production level of between 550,000 and 650,000 bopd and gross reserves of between 1.65 to 3.0 billion boe with 95 percent of the reserves being oil. Phase 1 is expected to start production in late 2019.

The full field development costs have also been revised down from between NOK 170 and 220 billion (real 2015) to between NOK 160 and 190 billion (real 2015), due to market savings relating to Phase 1 and optimisation of the Phase 2 facilities concept. The concept selection for Phase 2 is expected to be made during the fourth quarter 2016 and a PDO to be submitted during the fourth quarter 2017. Phase 2 is expected to start production in 2022.

Appraisal

2016 appraisal well programme

Licence	Operator	WI	Well	Spud Date
PL609	Lundin Petroleum	40%	Re-enter 7220/11-3 (Alta-3)	Summer 2016

In 2016, Lundin Petroleum is planning to re-enter the Alta-3 appraisal well in the southern Barents Sea to deepen the well and conduct well tests.

During the reporting period Lundin Petroleum entered into a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig for the upcoming appraisal and exploration campaign in the southern Barents Sea. The contract encompasses three firm wells and six further well-slot options which can be called at Lundin Petroleum's election.

Exploration

2016 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL544	16/4-10	January	Fosen	40%	Lundin Petroleum	Dry
Southern Barents Sea						
PL609	Re-enter 7220/6-2	Third quarter	Neiden	40%	Lundin Petroleum	
PL533	n/a	Third quarter	Filicudi	35%	Lundin Petroleum	

In January 2016, the Lorry well in PL700 in the Norwegian Sea was announced as dry. The well failed to encounter the prognosed reservoir.

In March 2016, the Fosen well in PL544 in the North Sea was announced as dry. The well, which was drilled just south of Luno II, encountered a 160 metres reservoir section but was water-wet with oil shows.

Lundin Petroleum will drill a further two exploration wells offshore Norway during 2016 targeting net unrisked prospective resources of approximately 170 MMboe. The remaining 2016 exploration programme consists of the Neiden re-entry in PL609 (WI 40%) and the Filicudi prospect in PL533 (WI 35%) just south of the Johan Castberg discovery in the southern Barents Sea.

Licence awards, transactions and relinquishments

In December 2015, Lundin Petroleum submitted licence applications to the Norwegian Ministry of Petroleum and Energy for blocks offered for licensing through the 23rd licensing round. Licence awards are expected to be announced in the summer of 2016.

In January 2016, the Ministry of Petroleum and Energy announced the licence awards in the 2015 APA licensing round. Lundin Petroleum was awarded four licences of which two were awarded to Lundin Petroleum as operator.

During the reporting period, Lundin Petroleum relinquished PL438, PL555, PL631, PL673, PL674, PL741 and PL579. During the same period, Lundin Petroleum was awarded operatorship of PL815 and PL830 (both with WI 40%) in addition to partnership in PL678SB and PL831 (both with WI 20%).

South East Asia

Malaysia

Production

Production in Mboepd	WI	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Bertam	75%	**8.5**	–	5.5

Peninsular Malaysia

Net production from the Bertam field on Block PM307 (WI 75%) during the reporting period was in line with forecast at 8,500 boepd. The Bertam field has been producing from 11 wells as of mid-October 2015, however two of the wells have been shut-in for part of the reporting period. One of the shut-in wells has been successfully worked over and was put back into production during the reporting period whilst the second well will be worked over in the second quarter of 2016. The Bertam FPSO continues to achieve an excellent uptime with 98 percent uptime achieved for the reporting period.

In October 2015, the partnership drilled the successful Bertam-3 appraisal well which confirmed additional resources in the northeastern part of the field. A long-reach horizontal development well, the A15 well, is currently being drilled into the Bertam-3 area from the Bertam wellhead platform and will be put into production in the second quarter of 2016 and thus taking the total number of producing wells to 12. The drilling rig Western Prospero will come off contract towards the end of May 2016.

Sabah, East Malaysia

Lundin Petroleum completed the drilling of the Imbok well on Block SB307/308 (WI 65%) in early January 2016. The well encountered only oil shows in Miocene sands and was plugged and abandoned as dry. Following the Imbok well, the rig was moved to drill the Bambazon prospect, also on Block SB307/308, which encountered 15 metres of net reservoir pay with oil shows. However, no moveable oil was recovered from sampling and the well was plugged and abandoned as dry. The West Prospero rig subsequently moved to the Maligan prospect on Block SB307/308 and whilst gas shows were encountered, the well was plugged and abandoned as dry.

Farm-out agreements

Lundin Petroleum signed a farm-out agreement with Dyas in December 2015 whereby Lundin Petroleum has transferred a 20 percent working interest in Block SB307/308 (WI 65% after farm-out) and a 20 percent working interest in Block SB303 (WI 55% after farm-out), located offshore Sabah, East Malaysia. A 15 percent working interest has been transferred in Block PM328 (WI 35% after farm-out), located offshore Peninsular Malaysia.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Singa	25.9%	**1.7**	1.7	1.6

The production from the Singa field was substantially in line with forecast during the reporting period.

In October 2015, Lundin Petroleum announced the signing of a sale and purchase agreement to sell its business in Indonesia to PT Medco Energi Internasional TBK for a cash consideration of MUSD 22, with an effective date of 1 October 2015. The Indonesian assets include the non-operated interest in the producing Singa gas field and the operated interests in the South Sokang and Cendrawasih VII Blocks, as well as the joint study agreement in respect of the Cendrawasih VIII Block. Lundin Petroleum may also become entitled to certain contingent payments in respect of the Singa gas field and retains an option to receive a future interest in the Cendrawasih Blocks. Completion of the transaction occurred on 28 April 2016 and Lundin Petroleum will cease reporting the production contribution from Singa as of this date.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
France				
– Paris Basin	100%[1]	2.2	2.4	2.3
– Aquitaine	50%	0.4	0.5	0.4
Netherlands	Various	1.7	1.8	1.8
		4.3	4.7	4.5

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

France
Net production during the reporting period from France was slightly above forecast at 2,600 boepd. Good production performance has been achieved from certain fields in the Paris Basin which has been somewhat offset by a slight underperformance from the Courbey field in the Aquitaine Basin.

The Netherlands
Net production from the Netherlands was ahead of forecast during the reporting period at 1,700 boepd due to an assumed shut-in of the Slootdorp 6 and 7 wells (WI 7.2325%) having been delayed into the second quarter of 2016.

In 2016, Lundin Petroleum will participate in two non-operated onshore exploration and two offshore development wells.

Russia
In 2008, a significant oil discovery called Morskaya was made in the northern Caspian and is estimated to contain gross contingent resources of 157 MMboe. In May 2015, Lundin Petroleum announced that Rosnedra, the Russian licensing authorities, had issued a production licence for the Morskaya field (WI 70%). During the reporting period the exploration area of the Lagansky block surrounding the Morskaya field was relinquished.

Corporate Responsibility

During the reporting period, Lundin Petroleum recorded two incidents among contractors. A tragic fatal accident took place offshore Malaysia when a contractor undertook repair work on the FPSO export hose. A thorough investigation was undertaken and follow-up measures were implemented. The Lost Time Incident Rate was 1.18 per million hours worked and the Total Recordable Incident Rate was 2.36.

In May 2016, Lundin Petroleum issued its first sustainability report based on the Global Reporting Initiative, GRI G4 guidance, providing more qualitative and quantitative sustainability data. As a result, Lundin Petroleum has modified its reporting of HSE Key Performance Indicators (KPIs) to track incidents per million hours worked instead of the prior 200,000 hours basis.

FINANCIAL REVIEW

Result
The net result for the three month period ended 31 March 2016 amounted to MUSD 114.3 (MUSD -230.9). The profit for the reporting period was mainly driven by the excellent production performance and a net foreign exchange gain as a result of the weakening US Dollar against the Norwegian Krone and the Euro, partially offset by lower oil prices and expensed exploration costs. The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 115.4 (MUSD -229.9) representing earnings per share of USD 0.37 (USD -0.74).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 124.9 (MUSD 86.0) representing EBITDA per share of USD 0.40 (USD 0.28). Operating cash flow for the reporting period amounted to MUSD 162.6 (MUSD 155.7) representing operating cash flow per share of USD 0.53 (USD 0.50).

Changes in the Group
There have been no significant changes in the Group during the reporting period.

Revenue

Revenue for the reporting period amounted to MUSD 191.3 (MUSD 121.3) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 191.0 (MUSD 126.6). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 33.07 (USD 52.71) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 33.94 (USD 53.94) per barrel.

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

Sales Average price per boe expressed in USD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Crude oil sales			
Norway			
– Quantity in Mboe	4,205.1	1,704.8	5,939.4
– *Average price per boe*	*32.42*	*53.61*	*52.97*
France			
– Quantity in Mboe	196.3	203.3	971.4
– *Average price per boe*	*33.88*	*57.86*	*52.07*
Netherlands			
– Quantity in Mboe	0.7	0.5	1.2
– *Average price per boe*	*30.48*	*62.32*	*50.20*
Malaysia			
– Quantity in Mboe	675.6	–	1,455.6
– *Average price per boe*	*35.21*	–	*48.92*
Total crude oil sales			
– Quantity in Mboe	**5,077.7**	1,908.6	8,367.6
– Average price per boe	***32.90[1]***	*54.07*	*52.16*
Gas and NGL sales			
Norway			
– Quantity in Mboe	405.4	195.8	745.7
– *Average price per boe*	*31.38*	*49.59*	*44.21*
Netherlands			
– Quantity in Mboe	155.0	160.9	633.3
– *Average price per boe*	*26.02*	*41.95*	*38.88*
Indonesia			
– Quantity in Mboe	138.7	136.8	527.7
– *Average price per boe*	*51.87*	*50.87*	*50.99*
Total gas and NGL sales			
– Quantity in Mboe	699.1	493.5	1,906.7
– *Average price per boe*	*34.26*	*47.46*	*44.31*
Total sales			
– Quantity in Mboe	**5,776.8**	2,402.1	10,274.3
– Average price per boe	***33.07[1]***	*52.71*	*50.71*

[1] Includes MUSD 0.3 additional sales revenue achieved by Lundin Petroleum Marketing SA

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

The change in under/over lift position amounted to a net charge of MUSD 5.3 (MUSD 8.4) in the reporting period. There was a net overlift of entitlement movement on the Norwegian producing fields during the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 5.6 (MUSD 3.1) for the reporting period and included Bertam FPSO lease income, a quality differential compensation on Alvheim blended crude, 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 58.7 (MUSD 25.2) and are detailed in the table below.

Production costs	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cost of operations			
– In MUSD	42.2	21.4	121.1
– In USD per boe	*7.45*	*9.20*	*10.27*
Tariff and transportation expenses			
– In MUSD	9.3	2.5	11.8
– In USD per boe	*1.64*	*1.10*	*1.00*
Royalty and direct production taxes			
– In MUSD	0.8	0.7	3.5
– In USD per boe	*0.13*	*0.31*	*0.29*
Change in inventory position			
– In MUSD	0.2	-2.4	-12.6
– In USD per boe	*0.03*	*-1.04*	*-1.07*
Other			
– In MUSD	6.2	3.0	26.5
– In USD per boe	*1.10*	*1.30*	*2.25*
Total production costs			
– In MUSD	**58.7**	25.2	150.3
– In USD per boe	*10.35*	*10.87*	*12.74*

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

The total cost of operations for the reporting period was MUSD 42.2 (MUSD 21.4). The increase compared to the same period last year is due to the contribution of the Edvard Grieg and Bertam fields which commenced production in November 2015 and April 2015 respectively, and well intervention work on the Bertam field performed in the first quarter of 2016. The total cost of operations excluding operational projects amounted to MUSD 37.4 (MUSD 20.3).

The cost of operations per barrel including operational projects amounted to USD 7.45 (USD 9.20) for the reporting period and excluding operational projects, the cost of operations amounted to USD 6.60 (USD 8.75) per barrel. The cost of operations per barrel amounts are both lower than the guidance provided in February 2016.

Tariff and transportation expenses for the reporting period amounted to MUSD 9.3 (MUSD 2.5). The increase compared to comparative period is mainly due the impact of the Edvard Grieg field which commenced production in November 2015.

Other costs amounted to MUSD 6.2 (MUSD 3.0) and mainly related to the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price curve at the end of 2015, an asset was recognised as at 31 December 2015. This asset is being charged to the income statement over the remaining term of the arrangement.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 97.3 (MUSD 43.1) and are detailed in Note 3. The depletion costs associated with oil and gas properties amounted to MUSD 97.3 (MUSD 43.1) at an average rate of USD 17.14 (USD 18.55) per barrel. The higher depletion costs for the reporting period compared to the same period last year is due to the depletion charge associated with the Edvard Grieg and Bertam fields, partly offset by a lower Brynhild field depletion rate following the impairment taken at the end of 2015.

Depletion of other assets amounted to MUSD 7.8 (MUSD —) for the reporting period and related to the Bertam FPSO which was depreciated from April 2015.

Exploration costs

Exploration costs expensed in the income statement for the reporting period amounted to MUSD 71.1 (MUSD 45.4) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the reporting period, exploration costs relating to Norway of MUSD 54.5 were expensed and mainly related to the unsuccessful exploration wells that were drilled in PL700 (Lorry) and PL544 (Fosen). In addition, exploration costs were expensed relating to Malaysia of MUSD 16.6 following the drilling of the unsuccessful Bambazon and Maligan wells in SB307/308.

General, administrative and depreciation expenses

The general administrative and depreciation expenses for the reporting period amounted to MUSD 9.0 (MUSD 11.3) which included a charge of MUSD 1.1 (MUSD 0.6) in relation to the Group’s long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the reporting period amounted to MUSD 1.3 (MUSD 1.1).

Finance income

Finance income for the reporting period amounted to MUSD 159.0 (MUSD 0.9) and is detailed in Note 4.

The net foreign currency exchange gain for the reporting period amounted to MUSD 158.6 (loss of MUSD 204.0). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group’s reporting entities. The US Dollar weakened against the Euro during the reporting period resulting in a net foreign currency exchange gain on the US Dollar denominated external loan which is borrowed by a subsidiary using Euro as functional currency. In addition, the Norwegian Krone strengthened against the Euro in the reporting period, generating a net foreign currency exchange gain on an intercompany loan balance denominated in Norwegian Krone. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar. For the reporting period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 17.9 (MUSD 41.0).

Finance costs

Finance costs for the reporting period amounted to MUSD 49.0 (MUSD 226.1) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 34.2 (MUSD 11.8) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 3.1 (MUSD 9.8) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense has increased compared to the same period last year due to the higher borrowings. The result on interest rate hedge settlements amounted to a loss of MUSD 4.3 (MUSD 1.8) and increased compared to the comparative period due to the higher fixed interest rate that was hedged in 2016.

The amortisation of the deferred financing fees amounted to MUSD 5.7 (MUSD 2.9) for the reporting period and related to the expensing of the fees incurred in establishing the financing facilities, including the Norwegian exploration refund facility, over the period of usage of the facilities.

Loan facility commitment fees for the reporting period amounted to MUSD 1.2 (MUSD 3.0) with the decrease compared to same period last year being due to the increased borrowings under the financing arrangements.

Tax

The overall tax credit for the reporting period amounted to MUSD 56.9 (tax charge of MUSD 2.0).

The current tax credit for the reporting period amounted to MUSD 30.0 (MUSD 59.6) which included MUSD 30.1 (MUSD 61.1) relating to the Norway exploration tax refund due to the development and exploration and appraisal expenditure in Norway in the reporting period and the tax depreciation on development expenditure incurred in prior years. The current tax credit in Norway for the reporting period is partly offset by the current tax charge relating to other Group operations.

The deferred tax credit for the reporting period amounted to MUSD 26.9 (charge of MUSD 61.6) which predominantly related to Norway. The deferred tax amount arises primarily where there is a difference in depletion for tax and accounting purposes.

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 and 78 percent. The effective tax rate for the reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange gain and Malaysian exploration costs, and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -1.1 (MUSD -1.0) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,315.9 (MUSD 4,015.4) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015– 31 Mar 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway	168.4	240.1	880.7
France	0.9	9.4	16.9
Netherlands	0.7	1.0	2.7
Indonesia	0.1	–	-1.1
Malaysia	6.8	53.4	130.1
	176.9	303.9	1,029.3

An amount of MUSD 168.4 (MUSD 240.1) of development expenditure was incurred in Norway during the reporting period, primarily on the Johan Sverdrup and Edvard Grieg field developments. In Malaysia, MUSD 6.8 (MUSD 53.4) was incurred during the reporting period on the Bertam field A15 development well.

Exploration and appraisal expenditure in MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015– 31 Mar 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway	40.9	80.4	370.2
France	0.1	0.1	0.4
Indonesia	–	0.4	3.1
Malaysia	21.3	0.9	33.3
Russia	0.3	0.6	5.3
Other	0.1	0.1	1.5
	62.7	82.5	413.8

Exploration and appraisal expenditure of MUSD 40.9 (MUSD 80.4) was incurred in Norway during the reporting period, primarily on the Fosen well in PL544 and the Lorry well in PL700 which were drilling at year end 2015. In Malaysia, MUSD 21.3 (MUSD 0.9) was incurred during the reporting period principally on the Bambazon and Maligan exploration wells.

Other tangible fixed assets amounted to MUSD 194.1 (MUSD 204.3) and included the accounting book value of the Bertam FPSO.

Financial assets amounted to MUSD 12.4 (MUSD 10.7) and are detailed in Note 8. Other shares and participations amounted to MUSD 9.6 (MUSD 4.1) and related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income. Brynhild operating cost share amounted to MUSD 2.2 (MUSD 5.5) and related to the long-term portion of the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price.

Deferred tax assets amounted to MUSD 14.6 (MUSD 13.4) and are mainly related to Malaysia following the impairment of the Bertam field at year end 2015 resulting in the depreciable tax pool value being higher than the accounting book value.

Other non-current assets amounted to MUSD 31.5 (MUSD –) and related to the Norwegian corporate tax refund in respect of the current year which will be received in December 2017.

Current assets

Inventories amounted to MUSD 49.7 (MUSD 45.6) and included both well supplies mainly held in Norway and Malaysia and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 226.2 (MUSD 159.3) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 107.2 (MUSD 35.2) and included invoiced Edvard Grieg cargoes. Underlift amounted to MUSD 23.3 (MUSD 26.5) and was mainly attributable to a net underlift position in Norway from the Edvard Grieg field. Joint operations debtors relating to various joint venture receivables amounted to MUSD 37.7 (MUSD 48.4). Prepaid expenses and accrued income amounted to MUSD 38.6 (MUSD 29.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 13.7 (MUSD 14.7) and related to the short-term portion of the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price. Other current assets amounted to MUSD 5.7 (MUSD 5.0) and included VAT and other miscellaneous receivable balances.

Current tax assets amounted to MUSD 282.2 (MUSD 264.7) and mainly related to the Norwegian corporate tax refund in respect of 2015 which will be received in December 2016.

Cash and cash equivalents amounted to MUSD 68.1 (MUSD 71.9). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,966.2 (MUSD 3,834.8) and are detailed in Note 11. Bank loans amounted to MUSD 4,090.0 (MUSD 3,858.0) and related to the outstanding loan under the Group's reserve-based lending facility. Capitalised financing fees relating to the establishment costs of the financing facilities, including the Norwegian exploration refund facility, amounted to MUSD 123.8 (MUSD 23.2) and are being amortised over the expected life of the financing facilities.

Provisions amounted to MUSD 410.1 (MUSD 379.9) and are detailed in Note 12. The provision for site restoration amounted to MUSD 396.7 (MUSD 368.2) and related to future decommissioning obligations. The provision has increased during the reporting period due to additions relating to the Norwegian development projects. Farm-in payment amounted to MUSD 5.2 (MUSD 4.6) and related to a provision for payments towards historic costs based on production milestones on Block PM307, Malaysia.

Deferred tax liabilities amounted to MUSD 544.4 (MUSD 542.6) of which MUSD 405.5 (MUSD 407.9) related to Norway. The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

Derivative instruments amounted to MUSD 35.8 (MUSD 48.4) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedges due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 32.7 (MUSD 32.2) and mainly represent 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

Trade and other payables amounted to MUSD 312.2 (MUSD 349.9) and are detailed in Note 13. Deferred revenue amounted to MUSD 3.8 (MUSD 20.2) and represented a payment advanced by the buyer under the Alvheim Blend oil sales contract. Once the buyer lifts the oil, the liability will be reversed and the revenue will be recognised in the income statement. Joint operations creditors and accrued expenses amounted to MUSD 256.9 (MUSD 271.5) and related mainly to the development and drilling activity in Norway and Malaysia. Other accrued expenses amounted to MUSD 23.4 (MUSD 23.7) and other current liabilities amounted to MUSD 6.6 (MUSD 11.4).

Derivative instruments amounted to MUSD 33.3 (MUSD 66.1) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 6.8 (MUSD 4.8) and related to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

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 -12.4 (MSEK -17.2) for the reporting period.

The result included general and administrative expenses of MSEK 13.1 (MSEK 25.7) and net finance costs of MSEK 0.3 (MSEK -1.8).

Pledged assets of MSEK 5,078.1 (MSEK 3,569.7) relate to the accounting value of the pledge of the shares in respect of the financing facility entered into by its fully-owned subsidiary Lundin Petroleum BV, see also the Liquidity section below.

Related Party Transactions

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

The Group received MUSD 0.1 (MUSD 0.1) from related parties for the provision of office and other services.

Liquidity

In February 2016, Lundin Petroleum replaced its existing USD 4.0 billion lending facility, which was due to reduce in availability from June 2016 and mature in 2019, with a committed seven year senior secured reserve-based lending facility of up to USD 5.0 billion, with an initial committed amount of USD 4.303 billion. The committed amount has subsequently been increased to USD 4.488 billion. The financing facility is a reserve-based lending 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 and fields under development at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 31 March 2016 is MUSD 626.7 (MUSD 422.9) equivalent and represents the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above.

In April 2015, Lundin Petroleum entered into a NOK 4.5 billion Norwegian exploration refund facility with ten international banks. The facility is secured against the tax refunds generated from Lundin Norway's exploration and appraisal activities on the Norwegian Continental Shelf and extends until the end of 2016. Following the receipt of the 2014 Norwegian exploration tax refund in December 2015, the facility size was reduced to NOK 2.15 billion. As at 31 March 2016, the amount outstanding under the exploration refund facility was NOK 1.24 billion.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas). Bank guarantees have been issued in support of the work commitments and other related costs in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 31 March 2016 was MUSD 15.7.

Subsequent Events

In May 2016, Lundin Petroleum announced that it will acquire Statoil's 15 percent working interest in the Edvard Grieg field in Norway, including the associated interests in the Edvard Grieg oil pipeline and Utsira High gas pipeline. In consideration for the acquisition of the assets, Lundin Petroleum AB will issue 27,580,806 new shares to Statoil ASA. In addition, Lundin Petroleum AB will transfer 2,000,000 shares held in treasury and issue 1,735,309 new shares for a cash consideration. Following the transaction, Lundin Petroleum AB will have 340,386,445 shares outstanding and Statoil ASA will hold 20.1 percent of the issued shares. The deal is subject to the approval of the EGM and the Norwegian government.

Share Data

Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 311,070,330 shares with a quota value of SEK 0.01 each. At 31 March 2016 the Company holds 2,000,000 of its own shares.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2015 Annual Report and in the materials provided to shareholders in respect of the 2016 AGM, available on www.lundin-petroleum.com.

Unit Bonus Plan

The number of units relating to the awards made in 2013, 2014 and 2015 under the Unit Bonus Plan outstanding as at 31 March 2016 were 132,836, 247,306 and 438,732 respectively.

Performance Based Incentive Plan

The AGM 2015 resolved a long-term performance based incentive plan in respect of Group management and a number of key employees. The plan is effective from 1 July 2015 and the 2015 award has been accounted for from the second half of 2015. The total outstanding awards made in respect of 2015 are 694,011 which vest over three years from 1 July 2015 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 91.40 using an option pricing model.

The 2014 plan is effective from 1 July 2014 and the total outstanding number of awards made in respect of 2014 are 602,554. Each award was fair valued at the date of grant at SEK 81.40 using an option pricing model.

Accounting Policies
This interim report has been prepared in accordance with International Accounting Standard (IAS) 34, Interim Financial Reporting, and the Swedish Annual Accounts Act (SFS 1995:1554).

The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2015.

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

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

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 2015 Annual Report.

Derivative financial instruments
At 31 March 2016, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 651.0	MUSD 94.9	NOK 6.86:USD 1	Apr 2016 – Jun 2016
MNOK 2,058.4	MUSD 243.9	NOK 8.44:USD 1	Jul 2016 – Dec 2016
MNOK 1,839.2	MUSD 217.3	NOK 8.46:USD 1	Jan 2017 – Dec 2017
MNOK 1,926.3	MUSD 228.0	NOK 8.45:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

At 31 March 2016, Lundin Petroleum had also entered into the following interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR Rate per annum	Settlement period
2,000	1.50%	Apr 2016 – Dec 2016
1,500	2.32%	Jan 2017 – Dec 2017
1,000	3.06%	Jan 2018 – Dec 2018

Under IAS 39, subject to hedge effectiveness testing, all of the hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

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

	31 Mar 2016		31 Mar 2015		31 Dec 2015	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.6486	8.2692	7.7533	8.0895	8.0637	8.8090
1 USD equals Euro	0.9076	0.8783	0.8873	0.9295	0.9012	0.9185
1 USD equals Rouble	74.8552	67.0225	63.0779	58.0351	61.2881	74.1009
1 USD equals SEK	8.4646	8.1030	8.3267	8.6347	8.4303	8.4408

Consolidated Income Statement

Expressed in MUSD	Note	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Revenue	1	**191.3**	121.3	569.3
Cost of sales				
Production costs	2	-58.7	-25.2	-150.3
Depletion and decommissioning costs		-97.3	-43.1	-260.6
Depletion of other assets		-7.8	–	-23.7
Exploration costs		-71.1	-45.4	-184.1
Impairment costs of oil and gas properties		–	–	-737.0
Gross profit/loss	3	**-43.6**	7.6	-786.4
General, administration and depreciation expenses		-9.0	-11.3	-39.5
Operating profit/loss		**-52.6**	-3.7	-825.9
Net financial items				
Finance income	4	159.0	0.9	7.4
Finance costs	5	-49.0	-226.1	-617.9
		110.0	-225.2	-610.5
Profit/loss before tax		**57.4**	-228.9	-1,436.4
Income tax	6	56.9	-2.0	570.1
Net result		**114.3**	-230.9	-866.3
Attributable to:				
Shareholders of the Parent Company		115.4	-229.9	-861.7
Non-controlling interest		-1.1	-1.0	-4.6
		114.3	-230.9	-866.3
Earnings per share – USD[1]		0.37	-0.74	-2.79
Earnings per share fully diluted – USD[1]		0.37	-0.74	-2.79

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2016–31 Mar 2016 3 months**	1 Jan 2015–31 Mar 2015 3 months	1 Jan 2015–31 Dec 2015 12 months
Net result	**114.3**	-230.9	-866.3
Items that may be subsequently reclassified to profit or loss			
Exchange differences foreign operations	7.7	-18.4	-81.7
Cash flow hedges	49.1	-45.6	6.9
Available-for-sale financial assets	4.8	-0.3	-3.7
	61.6	-64.3	-78.5
Total comprehensive income	**175.9**	-295.2	-944.8
Attributable to:			
Shareholders of the Parent Company	174.7	-295.0	-934.8
Non-controlling interest	1.2	-0.2	-10.0
	175.9	-295.2	-944.8

Consolidated Balance Sheet

Expressed in MUSD	Note	31 March 2016	31 December 2015
ASSETS			
Non-current assets			
Oil and gas properties	7	4,315.9	4,015.4
Other tangible fixed assets		194.1	204.3
Financial assets	8	12.4	10.7
Deferred tax assets		14.6	13.4
Other non-current assets	9	31.5	–
Total non-current assets		**4,568.5**	4,243.8
Current assets			
Inventories		49.7	45.6
Trade and other receivables	10	226.2	159.3
Current tax assets		282.2	264.7
Cash and cash equivalents		68.1	71.9
Total current assets		**626.2**	541.5
TOTAL ASSETS		**5,194.7**	4,785.3
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		-322.8	-498.2
Non-controlling interest		25.3	24.1
Total equity		**-297.5**	-474.1
Liabilities			
Non-current liabilities			
Financial liabilities	11	3,966.2	3,834.8
Provisions	12	410.1	379.9
Deferred tax liabilities		544.4	542.6
Derivative instruments	14	35.8	48.4
Other non-current liabilities		32.7	32.2
Total non-current liabilities		**4,989.2**	4,837.9
Current liabilities			
Financial liabilities	11	150.0	–
Trade and other payables	13	312.2	349.9
Derivative instruments	14	33.3	66.1
Current tax liabilities		0.7	0.7
Provisions	12	6.8	4.8
Total current liabilities		**503.0**	421.5
Total liabilities		**5,492.2**	5,259.4
TOTAL EQUITY AND LIABILITIES		**5,194.7**	4,785.3

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cash flows from operating activities			
Net result	114.3	-230.9	-866.3
Adjustments for:			
Exploration costs	71.1	45.4	184.1
Depletion, depreciation and amortisation	106.4	44.2	286.9
Impairment of oil and gas properties	–	–	737.0
Current tax	-30.0	-59.6	-280.6
Deferred tax	-26.9	61.6	-289.5
Long-term incentive plans	3.8	2.2	15.2
Foreign currency exchange loss	-176.5	162.9	374.6
Interest expense	34.2	11.8	71.3
Other	13.2	7.7	40.9
Interest received	0.3	0.1	6.1
Interest paid	-37.0	-21.3	-110.1
Income taxes paid / received	-0.2	-3.9	335.6
Changes in working capital	29.6	-67.1	-193.7
Total cash flows from operating activities	**102.3**	-46.9	311.5
Cash flows from investing activities			
Investment in oil and gas properties	-239.6	-386.4	-1,443.3
Investment in other fixed assets	1.5	-21.9	-36.0
Investment in subsidiaries	–	–	-0.1
Investment in other shares and participations	–	-3.7	-3.7
Decommissioning costs paid	-0.8	-0.2	-10.6
Other payments	–	-0.1	-0.5
Total cash flows from investing activities	**-238.9**	-412.3	-1,494.2
Cash flows from financing activities			
Changes in long-term liabilities	232.6	425.5	1,171.0
Financing fees paid	-97.6	–	-3.3
Total cash flows from financing activities	**135.0**	425.5	1,167.7
Change in cash and cash equivalents	-1.6	-33.7	-15.0
Cash and cash equivalents at the beginning of the period	71.9	80.5	80.5
Currency exchange difference in cash and cash equivalents	-2.2	5.1	6.4
Cash and cash equivalents at the end of the period	**68.1**	51.9	71.9

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent Company					
At 1 January 2015	**0.5**	**8.8**	**422.2**	**431.5**	**34.2**	**465.7**
Comprehensive income						
Net result	–	–	-229.9	-229.9	-1.0	-230.9
Other comprehensive income	–	-65.1	–	-65.1	0.8	-64.3
Total comprehensive income	**–**	**-65.1**	**-229.9**	**-295.0**	**-0.2**	**-295.2**
Transactions with owners						
Value of employee services	–	–	0.4	0.4	–	0.4
Total transactions with owners	**–**	**–**	**0.4**	**0.4**	**–**	**0.4**
At 31 March 2015	**0.5**	**-56.3**	**192.7**	**136.9**	**34.0**	**170.9**
Comprehensive income						
Net result	–	–	-631.8	-631.8	-3.6	-635.4
Other comprehensive income	–	-8.0	–	-8.0	-6.2	-14.2
Total comprehensive income	**–**	**-8.0**	**-631.8**	**-639.8**	**-9.8**	**-649.6**
Transactions with owners						
Investment in subsidiaries	–	–	–	–	-0.1	-0.1
Value of employee services	–	–	4.7	4.7	–	4.7
Total transaction with owners	**–**	**–**	**4.7**	**4.7**	**-0.1**	**4.6**
At 31 December 2015	**0.5**	**-64.3**	**-434.4**	**-498.2**	**24.1**	**-474.1**
Comprehensive income						
Net result	–	–	115.4	115.4	-1.1	114.3
Other comprehensive income	–	59.3	–	59.3	2.3	61.6
Total comprehensive income	**–**	**59.3**	**115.4**	**174.7**	**1.2**	**175.9**
Transactions with owners						
Value of employee services	–	–	0.7	0.7	–	0.7
Total transaction with owners	**–**	**–**	**0.7**	**0.7**	**–**	**0.7**
At 31 March 2016	**0.5**	**-5.0**	**-318.3**	**-322.8**	**25.3**	**-297.5**

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Crude oil	167.1	103.2	436.5
Condensate	0.1	0.1	0.6
Gas	23.8	23.3	83.9
Net sales of oil and gas	**191.0**	126.6	521.0
Change in under/over lift position	-5.3	-8.4	25.6
Other revenue	5.6	3.1	22.7
Revenue	**191.3**	121.3	569.3

Note 2 – Production costs MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cost of operations	42.2	21.4	121.1
Tariff and transportation expenses	9.3	2.5	11.8
Direct production taxes	0.8	0.7	3.5
Change in inventory position	0.2	-2.4	-12.6
Other	6.2	3.0	26.5
	58.7	25.2	150.3

Note 3 – Segment information MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Norway			
Crude oil	136.3	91.4	314.6
Gas	12.7	9.7	33.0
Net sales of oil and gas	**149.0**	101.1	347.6
Change in under/over lift position	-5.1	-8.5	25.9
Other revenue	0.4	0.5	2.0
Revenue	**144.3**	93.1	375.5
Production costs	-41.6	-17.7	-104.5
Depletion and decommissioning costs	-75.9	-33.2	-158.9
Exploration costs	-54.5	-44.9	-146.5
Impairment costs of oil and gas properties	–	–	-526.0
Gross profit/loss	**-27.7**	-2.7	-560.4

Note 3 – Segment information cont. MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
France			
Crude oil	6.7	11.8	50.6
Net sales of oil and gas	**6.7**	11.8	50.6
Change in under/over lift position	–	0.1	-0.2
Other revenue	0.3	0.4	1.5
Revenue	**7.0**	12.3	51.9
Production costs	-4.4	-3.7	-25.1
Depletion and decommissioning costs	-3.6	-4.1	-15.5
Exploration costs	–	–	-0.6
Gross profit/loss	**-1.0**	4.5	10.7
Netherlands			
Crude oil	–	–	0.1
Condensate	0.1	0.1	0.6
Gas	3.9	6.6	24.0
Net sales of oil and gas	**4.0**	6.7	24.7
Change in under/over lift position	-0.2	–	-0.1
Other revenue	0.5	0.4	1.8
Revenue	**4.3**	7.1	26.4
Production costs	-2.6	-2.8	-12.0
Depletion and decommissioning costs	-2.8	-2.8	-10.7
Exploration costs	–	-0.4	-0.7
Gross profit/loss	**-1.1**	1.1	3.0
Malaysia			
Crude oil	23.8	–	71.2
Net sales of oil and gas	**23.8**	–	71.2
Other revenue	3.7	–	10.8
Revenue	**27.5**	–	82.0
Production costs	-9.0	–	-4.4
Depletion and decommissioning costs	-15.0	–	-66.4
Depletion of other assets	-7.8	–	-23.7
Exploration costs	-16.6	–	-36.3
Impairment costs of oil and gas properties	–	–	-191.8
Gross profit/loss	**-20.9**	–	-240.6
Indonesia			
Gas	7.2	7.0	26.9
Net sales of oil and gas	**7.2**	7.0	26.9
Other revenue	–	–	–
Revenue	**7.2**	7.0	26.9
Production costs	-1.1	-1.0	-4.3
Depletion and decommissioning costs	–	-3.0	-9.1
Exploration costs	–	-0.1	–
Impairment costs of oil and gas properties	–	–	-19.2
Gross profit/loss	**6.1**	2.9	-5.7

Note 3 – Segment information cont. MUSD	1 Jan 2016– 31 Mar 2016 3 months	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Other			
Crude oil	0.3	–	–
Net sales of oil and gas	**0.3**	–	–
Other revenue	0.7	1.8	6.6
Revenue	**1.0**	1.8	6.6
Production costs	–	–	–
Gross profit/loss	**1.0**	1.8	6.6
Total			
Crude oil	167.1	103.2	436.5
Condensate	0.1	0.1	0.6
Gas	23.8	23.3	83.9
Net sales of oil and gas	**191.0**	126.6	521.0
Change in under/over lift position	-5.3	-8.4	25.6
Other revenue	5.6	3.1	22.7
Revenue	**191.3**	121.3	569.3
Production costs	-58.7	-25.2	-150.3
Depletion and decommissioning costs	-97.3	-43.1	-260.6
Depletion of other assets	-7.8	–	-23.7
Exploration costs	-71.1	-45.4	-184.1
Impairment costs of oil and gas properties	–	–	-737.0
Gross profit/loss	**-43.6**	7.6	-786.4

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

Note 4 – Finance income MUSD	1 Jan 2016– 31 Mar 2016 3 months	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Foreign currency exchange gain, net	158.6	–	–
Interest income	0.3	0.1	6.1
Guarantee fees	0.1	0.8	0.7
Other	–	–	0.6
	159.0	0.9	7.4

Note 5 – Finance costs MUSD	1 Jan 2016– 31 Mar 2016 3 months	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Interest expense	34.2	11.8	71.4
Foreign currency exchange loss, net	–	204.0	507.3
Result on interest rate hedge settlement	4.3	1.8	6.9
Unwinding of site restoration discount	3.3	2.3	10.0
Amortisation of deferred financing fees	5.7	2.9	12.4
Loan facility commitment fees	1.2	3.0	7.7
Other	0.3	0.3	2.2
	49.0	226.1	617.9

Note 6 – Income tax MUSD	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Current tax	-30.0	-59.6	-280.6
Deferred tax	-26.9	61.6	-289.5
	-56.9	2.0	-570.1

Note 7 – Oil and gas properties MUSD	**31 Mar 2016**	31 Dec 2015
Norway	3,278.8	2,987.5
France	192.8	187.0
Netherlands	31.0	31.5
Malaysia	298.0	301.6
Russia	497.6	490.2
Indonesia	17.7	17.6
	4,315.9	4,015.4

Note 8 – Financial assets MUSD	**31 Mar 2016**	31 Dec 2015
Other shares and participations	9.6	4.1
Brynhild operating cost share	2.2	5.5
Other	0.6	1.1
	12.4	10.7

Note 9 – Other non-current assets MUSD	**31 Mar 2016**	31 Dec 2015
Corporate tax	31.5	–
	31.5	–

Note 10 – Trade and other receivables MUSD	**31 Mar 2016**	31 Dec 2015
Trade receivables	107.2	35.2
Underlift	23.3	26.5
Joint operations debtors	37.7	48.4
Prepaid expenses and accrued income	38.6	29.5
Brynhild operating cost share	13.7	14.7
Other	5.7	5.0
	226.2	159.3

Note 11 – Financial liabilities

MUSD	31 Mar 2016	31 Dec 2015
Non-current:		
Bank loans	4,090.0	3,858.0
Capitalised financing fees	-123.8	-23.2
	3,966.2	3,834.8
Current:		
Short-term bank loans	150.0	–
	150.0	–
	4,116.2	3,834.8

Note 12 – Provisions

MUSD	31 Mar 2016	31 Dec 2015
Non-current:		
Site restoration	396.7	368.2
Long-term incentive plans	3.3	2.2
Farm-in payment	5.2	4.6
Other	4.9	4.9
	410.1	379.9
Current:		
Long-term incentive plans	6.8	4.8
	6.8	4.8
	416.9	384.7

Note 13 – Trade and other payables

MUSD	31 Mar 2016	31 Dec 2015
Trade payables	21.5	23.1
Deferred revenue	3.8	20.2
Joint operations creditors and accrued expenses	256.9	271.5
Other accrued expenses	23.4	23.7
Other	6.6	11.4
	312.2	349.9

Note 14 – Financial instruments
MUSD

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

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

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

31 March 2016 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	9.6	–	–
	9.6	–	–
Liabilities			
Derivative instruments – non-current	–	35.8	–
Derivative instruments – current	–	33.3	–
	–	**69.1**	–

31 December 2015 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	4.1	–	–
	4.1	–	–
Liabilities			
Derivative instruments – non-current	–	48.4	–
Derivative instruments – current	–	66.1	–
	–	114.5	–

There were no transfers between the levels during the reporting period.

The fair value of the financial assets is estimated to equal the carrying value. The fair value, of the Derivative instruments, is calculated using the forward interest rate curve and the forward exchange rate curve respectively for the interest rate swap and the currency hedging contracts. The hedge counterparties are all banks which are party to the loan facility agreement.

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Revenue	**1.0**	6.7	8.7
General and administration expenses	-13.1	-25.7	-89.6
Operating profit/loss	**-12.1**	-19.0	-80.9
Net financial items			
Finance income	0.5	1.8	4.6
Finance costs	-0.8	–	-1.8
	-0.3	1.8	2.8
Profit/loss before tax	**-12.4**	-17.2	-78.1
Income tax	–	–	–
Net result	**-12.4**	-17.2	-78.1

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Net result	**-12.4**	-17.2	-78.1
Other comprehensive income	–	–	–
Total comprehensive income	**-12.4**	-17.2	-78.1
Attributable to:			
Shareholders of the Parent Company	-12.4	-17.2	-78.1
	-12.4	-17.2	-78.1

Parent Company Balance Sheet

Expressed in MSEK	31 Mar 2016	31 Dec 2015
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Other tangible fixed assets	0.2	0.2
Total non-current assets	**7,872.0**	7,872.0
Current assets		
Receivables	21.4	17.5
Cash and cash equivalents	7.6	0.4
Total current assets	**29.0**	17.9
TOTAL ASSETS	**7,901.0**	7,889.9
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,770.0	7,782.4
Non-current liabilities		
Provisions	0.6	0.4
Payables to group companies	125.3	100.7
Total non-current liabilities	**125.9**	101.1
Current liabilities		
Current liabilities	5.1	6.4
Total current liabilities	**5.1**	6.4
Total liabilities	**131.0**	107.5
TOTAL EQUITY AND LIABILITIES	**7,901.0**	7,889.9
Pledged assets	5,078.1	3,569.7

Parent Company Cash Flow Statement

Expressed in MSEK	1 Jan 2016–31 Mar 2016 3 months	1 Jan 2015–31 Mar 2015 3 months	1 Jan 2015–31 Dec 2015 12 months
Cash flow from operations			
Net result	-12.4	-17.2	-78.1
Adjustment for non-cash related items	4.6	-0.7	0.3
Changes in working capital	-5.3	23.4	-23.8
Total cash flow from operations	**-13.1**	5.5	-101.6
Cash flow from financing			
Change in long-term liabilities	20.5	–	100.4
Total cash flow from financing	**20.5**	–	100.4
Change in cash and cash equivalents	7.4	5.5	-1.2
Cash and cash equivalents at the beginning of the period	0.4	1.8	1.8
Currency exchange difference in cash and cash equivalents	-0.2	-0.2	-0.2
Cash and cash equivalents at the end of the period	**7.6**	7.1	0.4

Parent Company Statement of Changes in Equity

	Restricted equity		Unrestricted equity			
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Total	Total equity
Balance at 1 January 2015	**3.2**	**861.3**	**2,295.3**	**4,700.7**	**6,996.0**	**7,860.5**
Total comprehensive income	**–**	**–**	**–**	**-17.2**	**-17.2**	**-17.2**
Balance at 31 March 2015	**3.2**	**861.3**	**2,295.3**	**4,683.5**	**6,978.8**	**7,843.3**
Total comprehensive income	**–**	**–**	**–**	**-60.9**	**-60.9**	**-60.9**
Balance at 31 December 2015	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**6,917.9**	**7,782.4**
Total comprehensive income	**–**	**–**	**–**	**-12.4**	**-12.4**	**-12.4**
Balance at 31 March 2016	**3.2**	**861.3**	**2,295.3**	**4,610.2**	**6,905.5**	**7,770.0**

Key Financial Data

Financial data (MUSD)	**1 Jan 2016– 31 Mar 2016 3 months**	1 Jan 2015 – 31 Mar 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Revenue	191.3	121.3	569.3
EBITDA	124.9	86.0	384.7
Net result	114.3	-230.9	-866.3
Operating cash flow	162.6	155.7	699.6

Data per share (USD)			
Shareholders' equity per share	-1.04	0.44	-1.61
Operating cash flow per share	0.53	0.50	2.26
Cash flow from operations per share	0.33	-0.12	1.01
Earnings per share	0.37	-0.74	-2.79
Earnings per share fully diluted	0.37	-0.74	-2.79
EBITDA per share	0.40	0.28	1.24
Dividend per share	–	–	–
Number of shares issued at period end	311,070,330	311,070,330	311,070,330
Number of shares in circulation at period end	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period fully diluted	310,193,392	309,678,433	310,019,890

Share price			
Share price at period end (SEK)	137.50	118.10	122.60

Key ratios			
Return on equity (%) [1]	–	-72	–
Return on capital employed (%)	-2	–	-26
Net debt/equity ratio (%) [1]	–	2,238	–
Equity ratio (%)	-6	3	-10
Share of risk capital (%)	4	22	1
Interest coverage ratio	-2	-1	-11
Operating cash flow/interest ratio	4	12	9
Yield	n/a	n/a	n/a

[1] As the equity at 31 December 2015 and 31 March 2016 is negative, these ratios have not been calculated.

Key Ratio Definitions

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

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

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

Operating cash flow per share: Operating cash flow 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 the awards outstanding under the Group's performance based incentive plan.

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

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

Weighted average number of shares for the period fully diluted: 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 after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

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

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

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

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

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

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

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

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

Financial Information

The financial information relating to the three month period ended 31 March 2016 has not been subject to review by the auditors of the Company.

Stockholm, 11 May 2016

Alex Schneiter
President and CEO

The Company will publish the following reports:

- The six month report (January—June 2016) will be published on 3 August 2016.
- The nine month report (January—September 2016) will be published on 2 November 2016.
- The year end report (January—December 2016) will be published on 1 February 2017.

The AGM will be held on 12 May 2016 in Stockholm, Sweden.

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