Lundin Petroleum

Report for the
NINE MONTHS
ended 30 September 2014

Q3

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Nine months ended 30 September 2014 (30 September 2013)

- Production of 25.9 Mboepd (33.3 Mboepd)[1]
- Revenue of MUSD 650.0 (MUSD 857.9)
- EBITDA of MUSD 506.9 (MUSD 737.7)
- Operating cash flow of MUSD 804.0 (MUSD 764.6)
- Net result of MUSD 5.1 (MUSD 49.9)
- Net debt of MUSD 2,054 (31 December 2013: MUSD 1,192)
- Alta oil discovery in the Barents Sea — gross recoverable resources estimated at between 125 and 400 MMboe
- Gohta appraisal well successfully completed in the Barents Sea
- Increased credit facility from USD 2.5 billion to USD 4.0 billion
- Johan Sverdrup Phase 1 conceptual development plan was approved by the licence partners
- Nine exploration licences awarded in the Norwegian 2013 APA licensing round, four as operator

Third quarter ended 30 September 2014 (30 September 2013)

- Production of 21.7 Mboepd (29.4 Mboepd)[1]
- Revenue of MUSD 189.2 (MUSD 263.8)
- EBITDA of MUSD 157.6 (MUSD 220.1)
- Operating cash flow of MUSD 307.0 (MUSD 266.0)
- Net result of MUSD 4.3 (MUSD 1.7)

	1 Jan 2014-30 Sep 2014 9 months	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Production in Mboepd[1]	**25.9**	**21.7**	33.3	29.4	32.7
Revenue in MUSD	**650.0**	**189.2**	857.9	263.8	1,132.0
Net result in MUSD	**5.1**	**4.3**	49.9	1.7	72.9
Net result attributable to shareholders of the Parent Company in MUSD	**8.8**	**5.6**	53.9	3.0	77.6
Earnings/share in USD[2]	**0.03**	**0.02**	0.17	0.01	0.25
EBITDA in MUSD	**506.9**	**157.6**	737.7	220.1	955.7
Operating cash flow in MUSD	**804.0**	**307.0**	764.6	266.0	967.9

[1] Including production from Russian onshore assets accounted for using the equity method under IFRS 11 Joint Arrangements up to completion of the sale of these assets in mid-July 2014.
[2] Based on net result attributable to shareholders of the Parent Company.

The comparatives in the financial statements have been restated following the adoption of IFRS 11 Joint Arrangements, effective 1 January 2014.

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,

Working in the oil and gas industry is certainly very interesting at the moment. There have been a number of material developments over the last few months with the fall in world oil prices and an industry which has finally woken up to the fact that the levels of cost inflation witnessed in recent years is unsustainable. At the same time the geopolitical uncertainty in the world has remained with recent events in the Middle East and Russia dominating the headlines. All of these issues directly affect our industry and impact commodity prices.

Lundin Petroleum is impacted by commodity prices and cost levels like all other oil and gas companies. However it is important for you, our shareholders, to understand that our business model and the continued success of our Company will be driven by our ability to increase our resource base much more than by oil prices. We have a strong balance sheet with access to multiple sources of liquidity and can withstand lower oil prices for long periods. We will manage our balance sheet prudently during times of uncertainty such as we are experiencing today but we will continue to spend money developing our discoveries as well as maintaining our exploration focus. We are in an industry which requires us to take a long term perspective and to do that, we need to invest. Our recent Alta discovery in the Barents Sea is excellent news for us all and it is very important that we continue to invest in this very prospective area to realise its full potential.

I remain as confident as ever that oil prices in the medium to long term will be strong. However it is very difficult to predict where oil prices will go in the short term with disappointing economic growth resulting in lower demand growth, increased production in North America, uncertainty as to how lower oil prices will impact drilling activity and uncertainty around the reaction from OPEC. At Lundin Petroleum we are prepared for all eventualities recognising that our world class projects such as Johan Sverdrup will supply the world with oil for the next 50 years and as such will remain extremely valuable.

Production to close to triple by the end of 2015

Our production for the first nine months of 2014 was 25,900 boepd. The third quarter production was in line with our forecasts but lower than previous quarters due to the planned maintenance on the Alvheim FPSO during the summer. Our 2014 production forecast is retained at 24,000 to 29,000 boepd.

Our forecast production will increase significantly in 2015 with production start-up from the Bøyla, Bertam and Edvard Grieg oil field developments. We retain our 2015 average production forecast of approximately 50,000 boepd and expect to exit 2015 in excess of 75,000 boepd when all these projects are onstream. We have been very busy over the last two to three years preparing the foundations for our next phase of growth with the investment in a number of development projects. We can now certainly see light at the end of the tunnel as these projects come to fruition and I am confident that we will achieve our forecast of tripling our production by the end of next year.

Development Projects

I indicated in my letter to shareholders in our half year report that first oil from the Brynhild development project, offshore Norway would likely slip into the fourth quarter. I am pleased to report that following the frustrating delays to Brynhild first oil we are now close to production. We expect over the next few weeks to see the recommencement of production from the Shell operated Pierce field which will then be followed by first oil from the Brynhild field. We still believe that based on the results of the completed wells there is potential that the gross initial Brynhild production rates of 12,000 boepd could be exceeded.

The news with regard to our other development projects, Bøyla, Bertam and Edvard Grieg is positive and I remain confident that all fields will commence production as forecast during 2015.

The progress on the Bertam development, offshore peninsular Malaysia is good with the successful installation of the Bertam wellhead platform topsides in October 2014 following the jacket installation in May 2014. The modification work on the 100 percent owned Bertam FPSO will be completed this year to allow deployment of the vessel into the field after the monsoon season in early 2015. First oil is still expected in the second quarter of 2015. The Seadrill owned West Prospero jack-up rig is making good progress with the drilling of the development wells.

We have continued to make good progress on the Edvard Grieg development following the successful installation of the jacket earlier this year. The topsides construction is progressing according to plan and will be ready for installation in the spring of 2015. The installation of the gas pipeline is now successfully completed. The Rowan Viking jack-up rig has commenced the development well drilling program for Edvard Grieg. As such, I remain confident that we will achieve first oil from Edvard Grieg in the fourth quarter of 2015.

The Bøyla field development is now substantially complete and I expect first oil early in 2015. The Bøyla field development is a subsea tieback to the Alvheim FPSO facility in which we also have an ownership interest. We are pleased to welcome Det Norske as operator of the Alvheim area fields and believe that the area contains the potential for further tieback development opportunities as well as exploration potential.

The Johan Sverdrup plan of development preparation is well advanced and will be submitted to the Norwegian Government for approval in early 2015. In tandem, the unitisation process is proceeding and will be resolved prior to the submission of the development plan. I believe that the Johan Sverdrup development project is coming to the market at an opportune time with the current reduction in market activity by many industry players.

The Johan Sverdrup subsurface work is now substantially complete. We look forward to being able to book Johan Sverdrup reserves early next year on submission of the development plan which will result in a three to four fold increase in our reserves.

Exploration

We are very excited with the recently completed Alta oil discovery in the Barents Sea. We have over the past years built a major licence ownership position in the Loppa High region of the Barents Sea located north of Statoil's Snøvhit development. We have always believed that this area had the potential to contain material commercial oil resources. The Alta discovery is our largest discovery in the Barents Sea to date containing between 125 and 400 million barrels of oil equivalent. This is certainly material and the fact that it is predominantly an oil discovery is very important. We are looking at all development options which will include standalone solutions as well as the feasibility of development with nearby discoveries. At the same time the area contains further potential and as such we intend to proceed with an aggressive 2015 drilling program in the Barents Sea which will include the appraisal of Alta as well as further exploration drilling. As I have said previously, I believe this part of the Barents Sea will become a material oil producing region in years to come.

Over recent months, many companies have reduced their exploration drilling programmes and budgets. At Lundin Petroleum we have been one of the most successful explorers over recent years with major success in the Utsira High area of the Norwegian North Sea and now in the Barents Sea. We believe exploration success is the best way to create shareholder value in our industry and as such we will continue with our aggressive exploration program with a focus on Norway and South East Asia. Between now and the end of 2014 we will drill six exploration wells including high impact wells such as Kopervik in the Utsira High area. In 2015 we will drill eight exploration wells targeting net unrisked resources of 490 MMboe. I am confident that this will lead to further exploration success.

The oil and gas industry

I spoke in my introduction about our industry finally recognising the level of cost inflation over recent years was unsustainable. The conclusion was clearly correct and action was needed. The reaction has been that over recent months we have seen a major reduction on capital expenditure in our industry which has put pressure on the oil service sector with material reductions in activity. Projects are being deferred and exploration spending has been significantly reduced with many companies reducing drilling activity in 2015. Unfortunately I think that reductions in work programmes are not necessarily the answer and will only result in negative impact upon supply in years to come. Our industry should focus more on standardisation and efficiency such as that achieved in the aerospace and automotive industries. We need to continue to spend money but to do that more efficiently. At Lundin Petroleum we will continue to invest particularly on exploration as we believe this is the best way to create shareholder value.

I mentioned to our Board recently that Lundin Petroleum has matured as a company over recent years. We have complemented our successful exploration team with an integrated development and operational capability. We have also expanded significantly our capabilities in South East Asia. Today, Lundin Petroleum has the capability to discover, develop and operate fields in an efficient, cost effective, safe and environmentally friendly manner. The foundations have been laid for our next phase of growth and whilst the oil and gas sector is currently out of favour with markets I am convinced this will ultimately be reflected in our market valuation. I want to thank all our shareholders for their support and patience in making this a reality.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 5 November 2014

Financial Report for the Nine Months Ended 30 September 2014

Operational Review

Lundin Petroleum has exploration and production assets focused upon three core areas, Norway, South East Asia and Continental Europe. Norway continues to represent the majority of Lundin Petroleum's operational activities with production for the nine month period ended 30 September 2014 (reporting period) accounting for 70 percent of total production and with 76 percent of Lundin Petroleum's total reserves as at the end of 2013.

Reserves and Resources

Lundin Petroleum has 194.1 million barrels of oil equivalent (MMboe) of reserves at the end of 2013 as certified by an independent third party. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. Excluding the major Johan Sverdrup field and the recently announced Alta discovery, both located in Norway, the best estimate contingent resources net to Lundin Petroleum amount to 342 MMboe as at the end of 2013. The Johan Sverdrup field contains gross contingent resources of between 1.8 and 2.9 billion boe as disclosed by pre-unit working operator Statoil. The Johan Sverdrup field is situated in licences PL501, PL502 and PL265 in Norway. Lundin Petroleum has a 40 percent interest in PL501 and a 10 percent interest in PL265. The Alta field, situated in PL609 in the Barents Sea was discovered in October 2014 and contains gross recoverable oil and gas resources of between 125 and 400 MMboe.

Production

Production for the reporting period amounted to 25.9 thousand barrels of oil equivalent per day (Mboepd) (compared to 33.3 Mboepd over the same period in 2013) and was comprised as follows:

Production in Mboepd	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Crude oil					
Norway	15.4	12.8	21.1	18.3	20.6
France	2.9	3.0	2.8	3.0	2.9
Russia[1]	1.5	0.32	2.4	2.2	2.3
Total crude oil production	**19.8**	**16.1**	26.3	23.5	25.8
Gas					
Norway	2.7	2.3	3.4	2.5	3.3
Netherlands	1.9	1.8	2.0	1.8	2.0
Indonesia	1.5	1.5	1.6	1.6	1.6
Total gas production	**6.1**	**5.6**	7.0	5.9	6.9
Total production					
Quantity in Mboe	**7,083.2**	**1,992.4**	9,079.7	2,704.3	11,939.6
Quantity in Mboepd	**25.9**	**21.7**	33.3	29.4	32.7

[1] Following the adoption of IFRS 11 Joint Arrangements, the financial results attributable to the onshore Russian assets are accounted for using the equity method from 1 January 2014.

[2] In July 2014, Lundin Petroleum sold its entire interest in the Sotchemyu-Talyu and North Irael fields in the Komi Republic to Arawak Energy Russia BV.

Norway

Production

Production in Mboepd	WI[1]	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Alvheim	15%	9.7	8.8	10.5	8.9	10.5
Volund	35%	7.8	5.9	12.6	11.3	12.2
Gaupe	40%	0.6	0.4	1.4	0.6	1.2
		18.1	**15.1**	24.5	20.8	23.9

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

Production from the Alvheim field during the reporting period has been better than forecast due to continued good reservoir performance, better FPSO uptime, and better than expected production from two wells which came back onstream during April 2014 following workover activity. The production outperformance was partially offset by two short weather related shut-ins of the Alvheim FPSO during the first quarter of 2014. Production on the Alvheim FPSO was shut-in for approximately two weeks during September 2014 for planned maintenance work and completion of the Bøyla (WI 15%) tie-in scope. One producing well on Alvheim has been shut-in since November 2013 and a workover of this well is scheduled during 2015. The drilling of a new infill well on Alvheim commenced during the fourth quarter of 2014 and the well is expected to commence production in early 2015. Two further infill wells are planned to be drilled in 2015 with production from these two wells expected to commence in late 2015 or early 2016. The development of the Viper/Kobra accumulations within the Alvheim field is anticipated to be sanctioned by the Alvheim partnership towards the end of 2014. The cost of operations for the Alvheim field, excluding well intervention work, was approximately USD 5 per barrel during the reporting period.

The Volund field production during the reporting period has been below forecast due to a combination of two short weather related shut-ins of the Alvheim FPSO, lower liquid throughput compared to the forecast and a higher water-cut than forecast. The production under performance has been partially offset by better than forecast FPSO uptime. Further infill opportunities have been identified on the Volund field and it is the intention to drill at least one infill well during 2016. The cost of operations for the Volund field during the reporting period was below USD 3.75 per barrel.

The Gaupe field produced as per forecast. The field is currently shut-in with the potential to recommence limited production in 2015 subject to economic conditions.

Development

Licence	Field	WI	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
PL148	Brynhild	90%	November 2011	23 MMboe	Q4 2014	12.0 Mboepd
PL340	Bøyla	15%	October 2012	22 MMboe	Q1 2015	20.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	186 MMboe	Q4 2015	100.0 Mboepd
Various	Ivar Aasen	1.385%	May 2013	192 MMboe	Q4 2016	65.0 Mboepd
Various	Johan Sverdrup	10% – 40%	Expected mid-2015	1.8 – 2.9 billion boe[1]	Late 2019	550.0 – 650.0 Mboepd

[1] Gross contingent resource range as disclosed by pre-unit working operator Statoil.

Brynhild
First oil from the Brynhild field is expected during the fourth quarter of 2014. The subsea template and manifolds, as well as the production and injection flow lines have been successfully installed. The first two of four development wells have been completed, flow tested and are ready for production. The two completed wells have found both the reservoir thickness and the quality of the reservoir as expected. A third well is currently being drilled. The Haewene Brim FPSO has been successfully re-moored at the Pierce field offshore United Kingdom and the new production risers have been hooked-up to the FPSO. Production restart of the Pierce field is expected shortly which will then be followed by first oil from the Brynhild field.

Bøyla
The Bøyla field is being developed as a 28 km subsea tie-back to the Alvheim FPSO with two production wells and one water injection well. The production manifold was successfully installed during the first quarter of 2014 and the Transocean Winner rig has completed the drilling of two wells and the top hole section of the final production well. Subsea work to tie in the first two wells is ongoing and first oil remains forecast for the first quarter of 2015. The last production well will be finalised and tied in later during the first quarter of next year.

Edvard Grieg
The Edvard Grieg field development is well advanced and is progressing on schedule and on budget. The steel jacket was successfully installed offshore during the second quarter of 2014 and the installation of the 94 km gas pipeline to the Sage Beryl gas system was completed during the third quarter 2014. The construction work of the topsides by Kværner is ongoing and is scheduled for mechanical completion by year end 2014 with onshore commissioning starting thereafter. Construction of the export oil pipeline is ongoing with the Y-connection into the Grane oil pipeline successfully installed. The installation of the topsides as well as the 43 km long oil pipeline to the Grane Y-connection is planned during the spring/summer of 2015. Development drilling commenced during the third quarter of 2014 with the Rowan Viking jack-up rig. First oil from the Edvard Grieg field is expected in the fourth quarter of 2015.

The appraisal well 16/1-18 on the southeastern part of the Edvard Grieg field was successfully completed during the reporting period. The well encountered 62 metres of moderate to good reservoir quality sandstone. A further appraisal well is planned in the southern part of Edvard Grieg during 2015 to better understand the distribution of this sandstone with the potential to increase reserves.

Ivar Aasen

During the reporting period the Ivar Aasen field, which is located immediately to the north of the Edvard Grieg field, has been unitised across three licences PL001b/PL242, PL338BS (WI 50%) and PL457. The PL338BS is a stratigraphic carve-out of PL338 with the same ownership as in PL338 (WI 50%). PL338BS has been assigned a 2.77 percent unitised interest in the Ivar Aasen development which therefore gives Lundin Petroleum a net ownership in Ivar Aasen of 1.385 percent. The unitised interest is not subject to any re-determination. The operator of Ivar Aasen, Det norske oljeselskap (Det norske), estimates the field to contain gross reserves of 192 MMboe excluding the Hanz discovery which is not a part of the Ivar Aasen unit. Ivar Aasen is being developed with a steel jacket platform with the topside facilities consisting of a living quarter and drilling facilities with oil, gas and water separation and onward export to the Edvard Grieg platform for final processing and pipeline export. Ivar Aasen is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

Lundin Petroleum discovered the Johan Sverdrup field in 2010 with the well 16/2-6 drilled on PL501 (WI 40%). A total of 22 wells and seven sidetracks have been drilled on the Johan Sverdrup field and the appraisal campaign is complete. In December 2013, Statoil, the pre-unit working operator of the field, released an updated gross contingent resource estimate for the Johan Sverdrup field of 1.8 to 2.9 billion boe and a first oil date of late 2019. The field spans over three licences PL501 (WI 40%), PL265 (WI 10%) and a small portion of the field extends into PL502.

During the reporting period, the Phase 1 conceptual development plan was announced. The Phase 1 development will contain a field centre, consisting of one processing platform, one riser platform, one wellhead platform with drilling facilities and one living quarter platform. The platforms will be installed on steel jackets in 120 metres of water and will be bridge-linked. A FEED contract for Phase 1 was awarded to Aker Solutions in late 2013. In June 2014, the pre-unit working operator announced that a letter of intent had been signed with Kværner in Norway for delivery of two of the steel jackets for the phase 1 development. The steel jacket for the riser platform is scheduled for delivery in 2017 and the steel jacket for the drilling platform is scheduled for delivery in 2018.

The first phase development is scheduled to start production in late 2019 and is forecast to have a gross production capacity of between 315 and 380 Mboepd. It is anticipated that between 40 and 50 production and injection wells will be drilled to support Phase 1 production, of which 11 to 17 wells will be drilled prior to first oil with a semi-submersible rig to facilitate Phase 1 plateau production.

The gross capital investment for Phase 1, which includes oil and gas export pipelines as well as a power supply from shore, is estimated to between NOK 100 and 120 billion, including contingencies and certain market allowances for potential future increases in market rates. The Phase 1 field centre will also have spare capacity to facilitate future phases of development and potential enhanced recovery.

The Johan Sverdrup oil and gas production will be transported to shore via dedicated oil and gas pipelines. A 274 km 36” oil pipeline will be installed and connected to the Mongstad oil terminal on the west coast of Norway. A 165 km 18” gas pipeline will be installed and connected to the Kårstø gas terminal for processing and onward transportation. A plan of development for Johan Sverdrup phase 1 is planned to be submitted for approval to the Norwegian Parliament in early 2015.

The Johan Sverdrup resources not developed as part of Phase 1 will be developed through subsequent development phases. The concept and costs of further development phases are currently being matured by all partners and will form the basis of later investment decisions.

During the reporting period, two appraisal wells have been completed on the Johan Sverdrup field. Well 16/3-8S was successfully completed on PL501 on the Avaldsnes High between wells 16/2-6, 16/2-7 and 16/3-4 encountering 13 metres of oil filled reservoir of late Jurassic Draupne sandstones. The well achieved an excellent test flow rate and measured exceptionally high permeabilities. A sidetrack 16/3-8ST2 was also successfully completed. In April 2014, the appraisal well 16/2-19 and sidetrack well 16/2-19A on PL265 were completed. The results from the wells were below expectations with thinner than expected reservoir towards the basement high.

Appraisal

2014 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL501	Lundin Petroleum	40%	16/3-8S & T2	January 2014	Completed March 2014
PL265	Statoil	10%	16/2-19	February 2014	Completed April 2014
PL492	Lundin Petroleum	40%	7120/1-4S	May 2014	Completed July 2014
PL359	Lundin Petroleum	50%	16/4-8S	June 2014	Completed August 2014

In addition to the Johan Sverdrup appraisal wells, a further two appraisal wells have been completed during the reporting period.

In July 2014 the appraisal well on the Gohta discovery in the Barents Sea was completed. The Gohta appraisal well 7120/1-4S on PL492 (WI 40%) encountered 10 metres of gas and condensate in Upper Permian limestone conglomerate with good reservoir properties overlying fractured limestone of limited reservoir quality. A test produced over 26 million standard cubic feet of gas per day (MMscfd) and 880 barrels of condensate per day.

The 16/4-8S appraisal well on PL359 (WI 50%) on the Luno II discovery on the Utsira High was completed in August 2014 and encountered a 30 metres gross oil column underlying a thin gas cap. The well flow tested oil successfully however the reservoir quality failed to meet pre-drill expectations. The revised gross contingent resource range for Luno II is estimated at 27 to 71 MMboe.

Lundin Petroleum is planning to drill three or four appraisal wells offshore Norway during 2015. Two of these appraisal wells are planned on the Alta discovery in PL609 (WI 40%) in the Barents Sea. One appraisal well is planned to be drilled on the south eastern part of the Edvard Grieg field on PL338 (WI 50%). A further appraisal well may be drilled on the Gohta discovery on PL492 (WI 40%) in 2015.

Exploration

2014 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL501	16/2-20A	January 2014	Torvastad (side-track)	40%	Lundin Petroleum	Oil shows — non-commercial
Barents Sea						
PL659	7222/11-2	January 2014	Langlitinden	20%	Det norske	Oil discovery — non-commercial
PL609	7220/11-1	August 2014	Alta	40%	Lundin Petroleum	Oil and Gas discovery — gross resources 125 — 400 MMboe
North Sea						
PL631	33/12-10S	September 2014	Vollgrav South	60%	Lundin Petroleum	Dry hole

Lundin Petroleum has completed four exploration wells in Norway so far in 2014. On the Utsira High the Torvastad side-track well 16/2-20A, targeting an Upper Jurassic reservoir sequence 770 metres west of the Torvastad exploration well 16/2-20, was completed in February 2014. The sidetrack encountered oil but found poorer than expected reservoir quality and was declared non-commercial.

In the Barents Sea, the Langlitinden well 7222/11-2 drilled on the southeast of the Loppa High was completed in February 2014. The well encountered oil in middle Triassic sandstone reservoir but the reservoir quality was poorer than expected and the well was consequently announced as non-commercial.

In October 2014, the Alta well 7220/11-1 in the Barents Sea was announced as an oil and gas discovery. The well was drilled on-trend with the Gohta discovery made in 2013 and encountered a 57 metre gross hydrocarbon column in carbonate rocks of good reservoir quality. The well flow tested approximately 3,300 barrels of oil per day and 1.7 million cubic feet of gas per day.

The Vollgrav South prospect drilled close to the Statfjord field with well 33/12-10S failed to encounter any hydrocarbons and was announced as a dry hole in October 2014.

Lundin Petroleum plans to drill another three exploration wells offshore Norway during 2014. For the remainder of 2014, the prospects Kopervik, Storm and Lindarormen will be drilled. The Storm prospect on PL555 (WI 60%), located in the northern North Sea, is currently drilling and is targeting 89 MMboe. In the Utsira High, the Kopervik prospect in PL625 (WI 40%), located to the northwest of the Johan Sverdrup field, is also currently drilling and is targeting 163 MMboe. In the fourth quarter of 2014, the Lindarormen well on PL584 (WI 60%) is scheduled to be drilled in the Norwegian Sea to the south of the Asgard field and to the southwest of the Draugen field and is targeting 194 MMboe.

During 2015, Lundin Petroleum is planning to drill seven operated exploration wells targeting net unrisked prospective resources of 475 MMboe.

Exploration wells 2015

Licence	WI	Targeting prospect
Barents Sea		
PL609	40%	Neiden
PL708	40%	Ørnen
Utsira High		
PL338	80%	Gemini
PL359	50%	Luno II North
PL674	35%	Zulu
PL544	40%	Fosen
Northern North Sea		
PL579	50%	Morkel

Lundin Petroleum, together with 32 other companies, has during the reporting period signed a contract with Western Geco and PGS for an extended 3D seismic acquisition in the Norwegian east Barents Sea ahead of the 23rd licensing round. The 3D acquisition was completed in the third quarter of 2014 and the processing is scheduled to be completed in the summer of 2015.

Licence awards, transactions and relinquishments

During the reporting period, Lundin Petroleum was awarded nine licences through the APA 2013 licensing round including four new licences in the Barents Sea. In addition, Lundin Petroleum acquired from Premier Oil a 30 percent interest in PL359 where Lundin Petroleum already held a 40 percent interest and is operator. Lundin Petroleum subsequently entered into two separate transactions whereby a five percent interest in PL359 was sold to OMV Norge AS and a 15 percent interest in PL359 was sold to Wintershall Norge AS. Following these transactions, both of which remain subject to government approval, Lundin Petroleum will have a 50 percent interest in PL359 and these transactions will also ensure full partner alignment between PL359 and PL338 where the Edvard Grieg field is located. In January 2014, Lundin Petroleum farmed out ten percent in PL546 (WI 50% after farm-out) to Petrolia Norway AS. In August 2014, Lundin Petroleum farmed-into PL674 acquiring a 35 percent working interest. During the reporting period, PL409 and PL570 were relinquished. PL338 will be split into two licences, subject to government approval. One licence will contain the Edvard Grieg field and the other licence in which Lundin Petroleum will hold an 80 percent interest will contain the remaining exploration potential of the licence including the Gemini and the Rolvsnes prospects.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
France						
– Paris Basin	100% [1]	2.4	2.5	2.4	2.6	2.5
– Aquitaine	50%	0.5	0.5	0.4	0.4	0.4
Netherlands	Various	1.9	1.8	2.0	1.8	2.0
		4.8	**4.8**	4.8	4.8	4.9

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

France

Production levels from France are substantially in line with forecast and incremental production from the Grandville redevelopment in the Paris Basin has been offsetting the natural decline from the other fields. A rig contract has been signed in relation to the Vert la Gravelle development with drilling activity expected to commence during the fourth quarter 2014.

The Hoplites exploration well on the Est Champagne concession (WI 100%) commenced drilling in October 2014 and is targeting unrisked prospective resources of 14 MMboe.

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

The K5-A5 (WI 2.03%) development well is currently drilling ahead with two further development wells and one exploration well expected to be drilled during 2015.

One exploration well on E17a/b (WI 1.20%) has been drilled during the reporting period and has encountered gas. Development options are currently being assessed. One development well on E17 is expected to be spud in the fourth quarter of 2014.

The Hempens-1 exploration well on the Leeuwarden licence (WI 7.2325%) was completed during the reporting period as a dry hole. The LW102ST development well also drilled on the Leeuwarden licence in the first quarter of 2014 was declared unsuccessful following testing.

The drilling of the Lambertschaag-2 exploration well on the Slootdorp licence (WI 7.2325%) was completed during the reporting period. The main target was found to be dry however gas was found in a shallower interval. Future plans for the well are being considered. One development well on Slootdorp is planned for 2015.

The Langezwaag-2 exploration well on the Gorredijk licence (WI 7.75%) has been completed. Gas was found in two intervals and preparations are ongoing to test the well.

South East Asia

Malaysia
The Bertam oil field, offshore Peninsular Malaysia, received development approval from Petronas in October 2013 with first oil expected in the second quarter of 2015. During the fourth quarter of 2014, Lundin Petroleum is planning to drill two exploration wells offshore Malaysia with one additional exploration well planned during 2015.

Offshore, Peninsular Malaysia
The Bertam field development on PM307 (WI 75%) is progressing according to schedule. During the reporting period the steel jacket was successfully completed and installed offshore Peninsular Malaysia. The construction of the topside of the wellhead platform at the TH Heavy Engineering yard was successfully installed on the steel jacket during October 2014. The Bertam FPSO (formerly the Ikdam FPSO) upgrade and life extension work is ongoing at the Keppel shipyard in Singapore and the completion of this work remains on schedule with expected completion during the fourth quarter 2014. During the third quarter of 2014, the jack-up drilling rig West Prospero commenced drilling the Bertam development wells. The subsurface development concept consists of 13 horizontal wells completed with electrical submersible pumps. During the topside installations work in the fourth quarter of 2014, the jack-up rig will be drilling exploration wells on SB307/SB308 (WI 42.5%) and on PM307.

The Bertam field is estimated to contain gross reserves of 18 MMboe and is being developed through an un-manned wellhead platform adjacent to the spread-moored Bertam FPSO with a total estimated development cost of MUSD 400, excluding any FPSO related costs. The Bertam field is expected to commence first oil in the second quarter of 2015 with a gross plateau rate of 15.0 Mbopd.

The Tembakau-2 appraisal well has been successfully completed with production test results from the I10 and I20 sands yielding 15.9 and 15.8 MMscfd respectively. The results of the well will now be incorporated into an updated resource estimate and conceptual development options will be reviewed.

One exploration well is planned to be drilled within Block PM307 during the fourth quarter of 2014 targeting the Mengkuang-1 oil prospect estimated to contain gross unrisked prospective resources of 21 MMboe. One further exploration well is planned to be drilled in late 2015 within PM307 on the Rengas oil prospect which is targeting gross unrisked prospective resources 22 MMboe. Both of these exploration wells will be drilled by the jack-up rig West Prospero.

During the third quarter of 2014, Lundin Petroleum entered into a farm-in agreement with Petronas Carigali whereby Lundin Petroleum has acquired a 50 percent working interest and operatorship in PM328. The PM328 Block is located northeast of PM307 and spans 5,600 km^2. The initial PSC term covers three years with a work programme commitment of acquiring 600 km^2 of 3D seismic within the first 18 months.

In October 2014, Lundin Petroleum signed an agreement to farm-out a 25 percent interest in Block PM308B with HiRex Petroleum. Following the completion of the farm-out agreement Lundin Petroleum will hold a 50 percent interest in PM308B.

East Malaysia, offshore Sabah
Lundin Petroleum continues to evaluate the potential for commercialisation of the Berangan, Tarap, Cempulut and Titik Terang gas discoveries in Block SB303 (WI 75%), most likely through a cluster development. These four discoveries are estimated to contain gross best estimate contingent resources of 347 bcf.

Seismic processing of the 500 km² Emerald 3D survey on SB307/308 (WI 42.5%) was completed in 2013 and two prospects, Maligan and Kitabu, within the Emerald 3D have been identified for drilling. The Kitabu prospect, which is estimated to contain gross unrisked prospective resources of 71 MMboe, is located on trend with the currently producing Shell fields SF30 and South Furious and commenced drilling by the West Prospero jack-up rig in October 2014.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Singa	25.9%	**1.5**	**1.5**	1.6	1.6	1.6

The production was slightly below forecast due to certain facility issues during the reporting period. The operator of the Singa field has informed that the planned two week shut-in of the field has been deferred from the third quarter of 2014 to the fourth quarter of 2014. The purpose of the shut-in is to allow for a re-routing of the pipeline which will increase the production from the Singa field . In early 2014, a revised gas sales agreement was put in place for the Singa field resulting in an increased gas sales price of USD 7.97 per million British Thermal Units (MMbtu) compared to the previous price of USD 5.20 per MMbtu with an effective date of 2 January 2014.

Exploration

Baronang/Cakalang
Exploration drilling on the Balqis and Boni prospect in the Baronang Block (WI 85%) in the Natuna Sea, Indonesia, was completed during the reporting period. Both wells encountered good quality reservoirs at the projected Oligocene level but neither well encountered any hydrocarbons and have been declared as dry holes. Lundin Petroleum is planning to relinquish both the Baronang and the Cakalang Blocks.

Gurita
In October 2014, Lundin Petroleum announced that the exploration well on the Gobi prospect in the Gurita Block (WI 90%) was unsuccessful and is being plugged and abandoned as a dry hole.

South Sokang
A 3D seismic acquisition programme of 1,000 km² has been completed on the South Sokang Block (WI 60%) in 2013. The seismic processing and interpretation is substantially complete with both oil and gas prospectivity identified at Miocene and Oligocene levels.

Cendrawasih VII
Lundin Petroleum is undertaking geological and technical studies on the Cendrawasih VII Block (WI 100%), offshore eastern Indonesia.

Other Areas

Russia

Production

Production in Mboepd	WI	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Komi Republic	50%	**1.5**	**0.3**	2.4	2.2	2.3

In July 2014, Lundin Petroleum sold its entire interest in the Sotchemyu-Talyu and North Irael fields in the Komi Republic to Arawak Energy Russia BV for a cash consideration.

Lagansky Block
In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery, Morskaya, was made in 2008 and is estimated to contain gross best estimate contingent resources of 157 MMboe. In October 2013, Lundin Petroleum announced a Heads of Agreement with Rosneft whereby Rosneft will acquire a 51 percent shareholding in LLC PetroResurs which owns a 100 percent interest in the Lagansky Block. The completion of the deal with Rosneft is uncertain due to a number of factors including the current sanctions. Lundin Petroleum is currently pursuing alternative partnership options in relation to the Lagansky Block.

Corporate Responsibility

During the reporting period, Lundin Petroleum had two low severity Lost Time Incidents (LTI) among its contractors, which resulted in a LTI frequency rate of 0.31 per 200,000 hours. The total recordable incident rate was 0.47.

In September 2014, Lundin Petroleum signed the UN Global Compact's "Call to Action", an appeal by companies to governments urging them to enhance measures to combat corruption. The Board of Directors approved of the decision to take this additional step in demonstrating Lundin Petroleum's commitment to anti-corruption.

In terms of disclosure regarding climate change, the Carbon Disclosure Project, CDP Nordic Report attributed a score of 90B to Lundin Petroleum. This is the highest score obtained among Nordic oil and gas companies. The highest score attributed to an energy company was 92A, while the average disclosure scores for the Nordic region is 80C and for Sweden 82B.

Financial Review

Result

The net result for the nine month period ended 30 September 2014 (reporting period) amounted to MUSD 5.1 (MUSD 49.9). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 8.8 (MUSD 53.9) representing earnings per share of USD 0.03 (USD 0.17).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 506.9 (MUSD 737.7) representing EBITDA per share of USD 1.62 (USD 2.38). Operating cash flow for the reporting period amounted to MUSD 804.0 (MUSD 764.6) representing operating cash flow per share of USD 2.57 (USD 2.47).

Changes in the Group

In July 2014, Lundin Petroleum completed the sale of its interests in the Russian onshore producing assets in the Komi Region.

Revenue

Revenue for the reporting period amounted to MUSD 650.0 (MUSD 857.9) 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 623.9 (MUSD 883.2). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 94.92 (USD 99.76) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 106.52 (USD 108.46) 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 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	4,001.8	790.9	6,079.7	2,138.2	7,925.4
– *Average price per boe*	*111.58*	*103.77*	*111.34*	*112.31*	*111.87*
France					
– Quantity in Mboe	804.9	351.9	797.4	363.9	1,030.4
– *Average price per boe*	*104.23*	*99.64*	*106.60*	*108.67*	*106.93*
Netherlands					
– Quantity in Mboe	1.1	0.5	1.2	–	1.8
– *Average price per boe*	*93.48*	*93.03*	*97.34*	–	*96.24*
Total crude oil sales					
– Quantity in Mboe	**4,807.8**	**1,143.3**	6,878.3	2,502.1	8,957.6
– Average price per boe	***110.34***	***102.49***	*110.78*	*111.78*	*111.30*
Gas and NGL sales					
Norway					
– Quantity in Mboe	865.0	226.7	1,047.5	285.7	1,389.4
– *Average price per boe*	*55.86*	*45.64*	*71.31*	*68.00*	*72.33*

Sales continued Average price per boe expressed in USD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Netherlands					
– Quantity in Mboe	526.5	163.9	531.2	167.3	715.7
– *Average price per boe*	*51.47*	*42.17*	*63.34*	*61.30*	*64.34*
Indonesia					
– Quantity in Mboe	373.8	130.2	396.1	132.2	520.1
– *Average price per boe*	*48.07*	*47.59*	*32.46*	*32.78*	*32.54*
Total gas and NGL sales					
– Quantity in Mboe	1,765.3	520.8	1,974.8	585.2	2,625.2
– *Average price per boe*	*52.90*	*45.03*	*61.37*	*58.13*	*62.27*
Total sales					
– Quantity in Mboe	**6,573.1**	**1,664.1**	8,853.1	3,087.3	11,582.8
– Average price per boe	***94.92***	***84.51***	*99.76*	*101.61*	*100.19*

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 credit of MUSD 13.8 (charge of MUSD 38.0) in the reporting period. There was an underlift of entitlement movement on the Alvheim and Volund fields during the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 12.3 (MUSD 12.7) for the reporting period and included the quality differential compensation received from the Vilje field owners to the Alvheim and Volund field owners, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 104.7 (MUSD 93.7) and are detailed in the table below.

Production costs	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Cost of operations					
– In MUSD	72.2	19.7	73.2	20.8	103.0
– *In USD per boe*	*10.84*	*10.06*	*8.68*	*8.29*	*9.28*
Tariff and transportation expenses					
– In MUSD	15.0	5.2	16.6	5.5	21.6
– *In USD per boe*	*2.25*	*2.65*	*1.97*	*2.20*	*1.95*
Royalty and direct production taxes					
– In MUSD	2.8	0.9	2.6	0.9	3.4
– *In USD per boe*	*0.42*	*0.47*	*0.30*	*0.32*	*0.31*
Change in inventory position					
– In MUSD	0.5	2.1	-0.1	2.2	-2.0
– *In USD per boe*	*0.08*	*1.10*	*-0.01*	*0.91*	*-0.18*
Other					
– In MUSD	14.2	-3.5	1.4	–	13.6
– *In USD per boe*	*2.13*	*-1.82*	*0.17*	–	*1.21*
Total production costs					
– In MUSD	**104.7**	**24.4**	93.7	29.4	139.6
– In USD per boe	***15.72***	***12.46***	*11.11*	*11.73*	*12.57*

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

The total cost of operations for the reporting period was MUSD 72.2 (MUSD 73.2) and included costs of MUSD 10.9 associated with well intervention work on two wells on the Alvheim field which was completed in the first quarter of 2014. There was well intervention work on the Alvheim and Volund fields, as well as radial drilling in the Paris Basin in the comparative period.

The cost of operations per barrel amounted to USD 10.84 (USD 8.68) for the reporting period including the Alvheim well intervention work and other operational projects. The increase in the cost of operations per barrel compared to the same period last year is due to the lower production volumes in the reporting period. The full year forecast for the cost of operations per barrel including operational projects is approximately USD 11.00 compared to the guidance of USD 12.20 given at the end of the second quarter. The decrease is mainly attributable to the impact of the Brynhild delay. Excluding operational projects, the cost of operations was MUSD 52.9 (MUSD 58.2) for the reporting period equating to USD 7.94 (USD 6.90) per barrel.

Other costs amounted to MUSD 14.2 (MUSD 1.4) and substantially relate to the cost share of the FPSO facilities to be used by the Brynhild field based on booked capacity. The FPSO cost share has been provided for the period up to forecast first oil and will be reported as cost of operations from first oil. Also included in other costs is the movement on the mark-to-market valuation of an operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. The credit of MUSD 3.5 to other costs in the third quarter of 2014 is primarily driven by the lower forward oil price curve resulting in a reversal of the provision booked at the end of the second quarter of 2014.

Depletion and decommissioning costs
Depletion costs amounted to MUSD 98.4 (MUSD 118.3) and are detailed in Note 3. Norway's contribution to the total depletion cost for the reporting period was 66 percent (75 percent) at an average rate of USD 13.19 (USD 13.35) per barrel. The lower depletion cost for the reporting period compared to the same period last year is in line with the lower production volumes.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 129.5 (MUSD 152.8) 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 74.2 were expensed and mainly related to the cost of drilling the wells on the Torvastad (PL501) and Langlitinden (PL659) prospects during the first quarter of 2014. A further MUSD 54.2 of exploration costs were expensed relating to Indonesia, being mainly costs expensed in the first quarter of 2014 associated with the Baronang and Cakalang Blocks following the results of the Balqis and Boni wells.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 42.0 (MUSD 29.8) which included a charge of MUSD 8.5 (MUSD 5.9) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation charges for the reporting period amounted to MUSD 3.7 (MUSD 3.2).

Finance income
Finance income for the reporting period amounted to MUSD 1.3 (MUSD 2.6) and is detailed in Note 4.

Finance costs
Finance costs for the reporting period amounted to MUSD 113.0 (MUSD 63.3) and are detailed in Note 5. Interest expenses for the reporting period amounted to MUSD 11.7 (MUSD 3.6) and represented the proportion of interest charged to the income statement. An additional amount of interest of MUSD 26.9 (MUSD 11.1) primarily associated with the funding of the Norwegian development projects was capitalised in the reporting period. Net foreign exchange losses for the reporting period amounted to MUSD 66.8 (MUSD 33.2). 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. During the reporting period, the US Dollar strengthened and this has resulted in the reported foreign exchange losses. Lundin Petroleum's underlying value is US Dollar based as this is the currency in which the majority of revenues are derived. A strengthening US Dollar currency has a positive overall value effect on the business as it increases the purchasing power of the US Dollar to purchase the currencies in which the Group incurs operational expenditure. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar as detailed in the Derivative financial instruments section below. During the reporting period, the net realised exchange gain on settled foreign exchange hedges amounted to MUSD 5.5 (MUSD 5.6). The amortisation of the deferred financing fees amounted to MUSD 9.8 (MUSD 6.5) for the reporting period and related to the expensing of the fees incurred in establishing the original USD 2.5 billion financing facility, and the subsequent increase to USD 4.0 billion in February 2014, over the period of usage of the facility.

Share of result of joint ventures accounted for using the equity method

Share of result of joint ventures accounted for using the equity method for the reporting period amounted to a loss of MUSD 12.9 (MUSD 0.1 gain) and included a MUSD 12.6 (MUSD —) non-cash expense relating to the carrying value of the onshore Russian assets following the agreement to sell the assets.

Tax

The overall tax charge for the reporting period amounted to MUSD 145.7 (MUSD 229.4).

The current tax credit for the reporting period amounted to MUSD 258.7 (MUSD 0.3) of which MUSD 274.4 (MUSD 16.2) related to Norway due to the significant level of 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 operations in France and the Netherlands.

The deferred tax charge for the reporting period amounted to MUSD 404.4 (MUSD 229.7) which predominantly related to Norway. The deferred tax charge 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 percent and 78 percent. The effective tax rate for the Group for the reporting period amounted to 97 percent. This effective rate is calculated from the face of the income statement and does not reflect the effective rate of tax paid within each country of operation. The high overall effective rate of tax for the reporting period is largely driven by Norway where the tax rate is 78 percent. In addition, there was not a full tax credit on the expensed exploration costs in Indonesia, net foreign exchange losses and the expense relating to the sale of the onshore Russian assets.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -3.7 (MUSD -4.0) 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 4,791.4 (MUSD 3,820.8) 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 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Norway	818.7	243.5	758.0	379.8	1,105.9
France	14.6	8.4	5.5	2.2	7.0
Netherlands	2.8	0.8	3.5	1.6	4.8
Indonesia	-0.6	-0.6	-1.0	—	-1.9
Malaysia	97.8	48.9	4.8	4.8	12.7
	933.3	**301.0**	770.8	388.4	1,128.5

An amount of MUSD 818.7 (MUSD 758.0) of development expenditure was incurred in Norway during the reporting period, of which MUSD 809.1 (MUSD 746.5) was invested in the Edvard Grieg, Brynhild and Bøyla field developments. In Malaysia, MUSD 97.8 (MUSD 4.8) was incurred during the reporting period on the Bertam field development.

An amount of MUSD 102.5 (MUSD 14.9) was incurred in the reporting period on upgrading the Bertam FPSO for use on the Bertam field, Malaysia. This amount is not shown in the table above and has been capitalised as part of other tangible fixed assets.

Exploration and appraisal expenditure in MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Norway	351.5	140.5	389.5	150.7	506.4
France	2.2	0.5	2.1	1.0	2.4
Indonesia	30.0	2.4	7.8	-0.7	18.5
Malaysia	30.0	18.6	33.2	7.3	36.1
Russia	2.6	0.7	3.7	1.6	6.0
Other	1.4	0.5	0.3	0.1	0.5
	417.7	**163.2**	436.6	160.0	569.9

Exploration and appraisal expenditure of MUSD 351.5 (MUSD 389.5) was incurred in Norway during the reporting period, primarily on the appraisal drilling of the Johan Sverdrup field and the Edvard Grieg southeastern extension, Gohta, and Luno II appraisal wells, as well as the Torvastad (PL501) Langlitinden (PL659), Alta (PL609) and Vollgrav (PL631) exploration wells. During the reporting period MUSD 30.0 (MUSD 7.8) was spent in Indonesia mainly on drilling of the Balqis and Boni wells on the Baronang Block and MUSD 11.4 (MUSD 25.9) in Malaysia on the appraisal drilling of Tembakau (PM307).

Other tangible fixed assets amounted to MUSD 184.2 (MUSD 85.0) and included amounts relating to the Bertam FPSO and to other fixed assets.

Investments accounted for using the equity method amounted to MUSD — (MUSD 24.6) following the sale of the onshore Russian assets in July 2014.

Financial assets amounted to MUSD 296.1 (MUSD 69.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 14.5 (MUSD 22.0) and mainly related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income. Long-term receivables amounted to MUSD — (MUSD 9.7) and the comparative amount related to the loan due from the sub-group which contained the onshore Russian assets that was accounted for using the equity method until the sale of the assets in July 2014. Deferred tax assets amounted to MUSD 20.5 (MUSD 22.4) and are mainly related to the part of the tax loss carry forwards in the Netherlands that are expected to be utilised against future tax liabilities. Corporate tax amounted to MUSD 259.8 (MUSD —) and is the Norwegian corporate tax refund in respect of the current year which will be received in December 2015. This is shown as part of financial assets and will be reclassified to current assets at the end of 2014. Bonds amounted to MUSD — (MUSD 10.4) following the sale of the Etrion Corporation bonds during the first quarter of 2014. Derivative instruments amounted to MUSD 0.1 (MUSD 3.0) and related to the mark-to-market gain on outstanding hedges due to be settled after twelve months, see also Derivative financial instruments section below.

Current assets

Receivables and inventories amounted to MUSD 157.1 (MUSD 279.6) and are detailed in Note 9.

Inventories amounted to MUSD 33.2 (MUSD 21.2) and included both hydrocarbon inventories and well supplies. Trade receivables amounted to MUSD 54.5 (MUSD 125.8) and included MUSD 33.8 (MUSD 102.5) relating to Norway. All trade receivables are current. Corporate tax amounted to MUSD 0.8 (MUSD 6.5) and the comparative as at 31 December 2013 included a tax refund due in France of MUSD 5.8 which was settled during the second quarter of 2014. Derivative instruments amounted to MUSD — (MUSD 3.2) and the comparative related to the mark-to-market gain on outstanding foreign currency contracts due to be settled within twelve months. Prepaid expenses and accrued income amounted to MUSD 40.6 (MUSD 61.7) and represented prepaid operational and insurance expenditure. Other current assets amounted to MUSD 9.3 (MUSD 26.6) and included VAT and other miscellaneous balances.

Cash and cash equivalents amounted to MUSD 111.9 (MUSD 82.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Provisions amounted to MUSD 1,669.8 (MUSD 1,345.1) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 254.3 (MUSD 241.6) and relates to future decommissioning obligations. The provision for deferred taxes amounted to MUSD 1,393.2 (MUSD 1,066.0) of which MUSD 1,254.5 (MUSD 924.6) related to Norway. The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction. The non-current portion of the provision for Lundin Petroleum's LTIP scheme amounted to MUSD 1.7 (MUSD 30.8). Lundin Petroleum's LTIP scheme is outlined in this report under the Remuneration section. The phantom option plan vested in May 2014 and 50 percent of the vested amount was paid during the second quarter of 2014. The second tranche of the phantom scheme payable within twelve months was reclassified to current liabilities in the second quarter of 2014. The remaining entitlement under the phantom option plan for the former VP Finance and CFO was settled during the third quarter of 2014 in accordance with the rules of the plan. Derivative instruments amounted to MUSD 8.4 (MUSD 1.6) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedges due to be settled after twelve months. Farm-in payment amounted to MUSD 7.5 (MUSD —) and relates to a provision for payments towards historic costs on Block PM307, Malaysia, see also Current liabilities section.

Financial liabilities amounted to MUSD 2,122.0 (MUSD 1,239.1). Bank loans amounted to MUSD 2,166.0 (MUSD 1,275.0) and related to the outstanding loan under the Group's increased USD 4.0 billion revolving borrowing base facility. Capitalised financing fees relating to the establishment costs of the financing facility amounted to MUSD 44.0 (MUSD 35.9) and are being amortised over the expected life of the financing facility. The increase in capitalised financing fees in the reporting period is attributable to the costs associated with increasing the financing facility to USD 4.0 billion.

Other non-current liabilities amounted to MUSD 26.8 (MUSD 25.0) and mainly arise from the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities
Current liabilities amounted to MUSD 540.9 (MUSD 439.2) and are detailed in Note 12.

The overlift position amounted to MUSD 8.0 (MUSD 29.2) and related to the net overlift of the Alvheim and Volund fields production entitlement at 30 September 2014. Joint venture creditors and accrued expenses amounted to MUSD 391.5 (MUSD 334.5) and related mainly to the increased development and drilling activity in Norway and the Bertam project. Other accrued expenses amounted to MUSD 61.5 (MUSD 39.4) and included an amount of MUSD 31.5 (MUSD 4.8) relating to the work done on the Bertam FPSO. The liability for the long-term incentive plan amounted to MUSD 29.1 (MUSD –) and represents the second tranche of the phantom option plan including social costs due within twelve months. The phantom option plan is now fully vested and the liability has been reclassified from provisions to current liabilities. Derivative instruments amounted to MUSD 25.6 (MUSD 4.0) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedge contracts due to be settled within twelve months.

Short term provisions amounted to MUSD 63.1 (MUSD 46.2) and includes an amount of MUSD 48.5 (MUSD –) relating to a payment for historic costs on Block PM307, Malaysia, which is payable on first oil from the Bertam project. An amount of MUSD 10.5 (MUSD –) is included relating to the Brynhild field cost share provided for the period to the first oil date, the mark-to-market valuation of the Brynhild operating cost share agreement and a provision for contractual obligations post the expected cessation of production date on the Gaupe field. Also included in short term provisions is an amount of MUSD 4.1 (MUSD 46.2) relating to the current portion of the provision for Lundin Petroleum's LTIP scheme.

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 -101.1 (MSEK -56.4) for the reporting period.

The result included general and administrative expenses of MSEK 109.8 (MSEK 58.1) and finance income of MSEK 3.0 (MSEK 2.4), mainly relating to guarantee fees.

Pledged assets of MSEK 12,991.0 (MSEK 12,014.5) 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 0.3 (MUSD 0.2) from ShaMaran Petroleum for the provision of office and other services. The Group paid MUSD 0.1 (MUSD 0.1) to other related parties in respect of aviation services received.

In 2013, the Group entered into a loan agreement with Geoff Turbott, former VP Finance and CFO for a maximum amount of MUSD 3.0. All amounts plus interest have been repaid during the reporting period.

Liquidity
On 25 June 2012, Lundin Petroleum entered into a seven year senior secured revolving borrowing base facility of USD 2.5 billion with a group of 25 banks to provide funding for Lundin Petroleum's ongoing exploration expenditure and development costs. On 6 February 2014, Lundin Petroleum increased the facility to USD 4.0 billion on similar terms. The 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 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 30 September 2014 is MUSD 1,794.6 (MUSD 1,870.3) equivalent and represents the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above. The Group is not in breach of the debt covenants.

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 30 September 2014 was MUSD 8.2.

Subsequent Events
Lundin Petroleum announced in October 2014 that the exploration wells Vollgrav South, Norway and Gobi-1, Indonesia were completed as dry wells. The costs of the wells and associated licence costs will be expensed in the fourth quarter of 2014.

In October 2014, Lundin Petroleum signed a rights offering standby purchase agreement in relation to a rights offering of CAD 75 million proposed to be made by ShaMaran Petroleum. If such offering proceeds, Lundin Petroleum, together with the major shareholders of ShaMaran Petroleum, has agreed to purchase all shares not otherwise subscribed for by rights holders other than the major shareholders. Lundin Petroleum holds 6.2 percent of the total shares of ShaMaran Petroleum as at 30 September 2014.

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.

During the reporting period Lundin Petroleum purchased a further 500,000 of its own shares at an average price of SEK 124.07. Following a 2014 AGM resolution, the Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount and in consequence the cancellation of shares did not impact the Company's share capital. This resulted in a minor change in the quota value 0f each share as no new shares were issued. At 30 September 2014 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 2013 Annual Report.

Unit Bonus Plan

The number of units relating to the 2012, 2013 and 2014 Unit Bonus Plans outstanding as at 30 September 2014 were 114,110, 270,316 and 372,267 respectively.

Phantom Option Plan

The plan for Executive Management includes 5,500,928 phantom options with an exercise price of SEK 52.91. The phantom options vested in May 2014 being the fifth anniversary of the date of grant. Each option was valued at SEK 81.45 based on the average share price for the fifth year of the plan amounting to SEK 134.36.

Performance Based Incentive Plan

The AGM 2014 has resolved a new long-term performance based incentive plan in respect of Group Management and a number of key employees. The plan is effective from 1st of July 2014 and the 2014 awards under the plan has been accounted for in the reporting period. The total number of awards made in respect of 2014 was 608,103 and the related cost is recognised over the three year performance period subject to certain performance conditions being met by Lundin Petroleum. 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.

As from 1 January 2014, Lundin Petroleum has adopted IFRS 11 Joint Arrangements and the comparatives for the prior year have been restated. For further information, please refer to the 2013 Annual Report, page 91. 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 2013.

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

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

Risks and Risk Management

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

A detailed analysis of Lundin Petroleum's strategic, operational, financial and external risks and mitigation of those risks through risk management is described in Lundin Petroleum's 2013 Annual Report.

Derivative financial instruments
At 30 September 2014, Lundin Petroleum had entered into the following currency hedging contracts to meet part of the 2014 and future NOK operational requirements as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 5,547.1	MUSD 897.4	NOK 6.18: USD 1	Jan 2014 – Dec 2014
MNOK 3,243.5	MUSD 517.7	NOK 6.27: USD 1	Jan 2015 – Dec 2015

During March 2013, Lundin Petroleum entered into a three year fixed interest rate swap, starting 1 April 2013 in respect of MUSD 500 of borrowings, fixing the floating LIBOR rate at approximately 0.57 percent per annum for the duration of the hedge. In March 2014, Lundin Petroleum entered into further interest rate hedge swaps starting 1 July 2014 and ending in December 2018 as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR Rate per annum	Settlement period
1,000	0.21%	1 Jul 2014 – 31 Dec 2014
1,500	0.52%	1 Jan 2015 – 31 Dec 2015
1,500	1.50%	1 Jan 2016 – 31 Mar 2016
2,000	1.50%	1 Apr 2016 – 31 Dec 2016
1,500	2.32%	1 Jan 2017 – 31 Dec 2017
1,000	3.06%	1 Jan 2018 – 31 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.

	30 Sep 2014		30 Sep 2013		31 Dec 2013	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	6.1081	6.4524	5.8145	6.0081	5.8753	6.0837
1 USD equals Euro	0.7378	0.7947	0.7592	0.7405	0.7529	0.7251
1 USD equals Rouble	35.4430	35.5496	31.6276	32.4502	31.8675	32.8653
1 USD equals SEK	6.6680	7.2689	6.5138	6.4106	6.5132	6.4238

Consolidated Income Statement in Summary

Expressed in MUSD	Note	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Revenue	1	**650.0**	**189.2**	857.9	263.8	1,132.0
Cost of sales						
Production costs	2	-104.7	-24.4	-93.7	-29.4	-139.6
Depletion and decommissioning costs		-98.4	-29.6	-118.3	-35.3	-169.3
Exploration costs		-129.5	-0.3	-152.8	-18.5	-287.8
Impairment costs of oil and gas properties		–	–	-123.4	-41.7	-123.4
Gross profit	3	**317.4**	**134.9**	369.7	138.9	411.9
General, administration and depreciation expenses		-42.0	-8.3	-29.8	-15.5	-41.2
Operating profit		**275.4**	**126.6**	339.9	123.4	370.7
Result from financial investments						
Finance income	4	1.3	0.3	2.6	0.8	3.4
Finance costs	5	-113.0	-74.5	-63.3	-27.0	-85.9
		-111.7	**-74.2**	-60.7	-26.2	-82.5
Share of the result of joint ventures accounted for using the equity method		-12.9	–	0.1	0.3	-0.2
Profit before tax		**150.8**	**52.4**	279.3	97.5	288.0
Income tax expense	6	-145.7	-48.1	-229.4	-95.8	-215.1
Net result		**5.1**	**4.3**	49.9	1.7	72.9
Attributable to:						
Owners of the Parent Company		8.8	5.6	53.9	3.0	77.6
Non-controlling interest		-3.7	-1.3	-4.0	-1.3	-4.7
		5.1	**4.3**	49.9	1.7	72.9
Earnings per share – USD[1]		0.03	0.02	0.17	0.01	0.25

The comparatives in the financial statements have been restated following the adoption of IFRS 11 Joint Arrangements, effective 1 January 2014.

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

Consolidated Statement of Comprehensive Income in Summary

Expressed in MUSD	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Net result	**5.1**	**4.3**	49.9	1.7	72.9
Other comprehensive income					
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-101.1	-84.8	-34.3	23.1	-31.7
Cash flow hedges	-37.1	-27.0	-13.3	3.7	-8.1
Available-for-sale financial assets	-6.3	-4.3	-0.9	1.4	1.9
Income tax relating to other comprehensive income	–	–	3.3	-1.0	1.9
Other comprehensive income, net of tax	-144.5	-116.1	-45.2	27.2	-36.0
Total comprehensive income	**-139.4**	**-111.8**	4.7	28.9	36.9
Attributable to:					
Owners of the Parent Company	-127.9	-104.4	11.3	29.5	44.7
Non-controlling interest	-11.5	-7.4	-6.6	-0.6	-7.8
	-139.4	**-111.8**	4.7	28.9	36.9

Consolidated Balance Sheet in Summary

Expressed in MUSD	Note	**30 September 2014**	31 December 2013
ASSETS			
Non-current assets			
Oil and gas properties	7	4,791.4	3,820.8
Other tangible fixed assets		184.2	85.0
Investments accounted for using the equity method		–	24.6
Financial assets	8	296.1	69.0
Total non-current assets		**5,271.7**	3,999.4
Current assets			
Receivables and inventories	9	157.1	279.6
Cash and cash equivalents		111.9	82.4
Total current assets		**269.0**	362.0
TOTAL ASSETS		**5,540.7**	4,361.4
EQUITY AND LIABILITIES			
Equity			
Shareholders' equity		1,069.9	1,207.0
Non-controlling interest		48.2	59.8
Total equity		**1,118.1**	1,266.8
Liabilities			
Non-current liabilities			
Provisions	10	1,669.8	1,345.1
Financial liabilities	11	2,122.0	1,239.1
Other non-current liabilities		26.8	25.0
Total non-current liabilities		**3,818.6**	2,609.2
Current liabilities			
Current liabilities	12	540.9	439.2
Provisions	10	63.1	46.2
Total current liabilities		**604.0**	485.4
Total liabilities		**4,422.6**	3,094.6
TOTAL EQUITY AND LIABILITIES		**5,540.7**	4,361.4

Consolidated Statement of Cash Flows in Summary

Expressed in MUSD	Note	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Cash flows from operating activities						
Net result		5.1	4.3	49.9	1.7	72.9
Adjustments for non-cash related items	14	500.4	146.1	687.9	223.2	880.1
Interest received		0.5	0.2	0.8	0.2	0.9
Interest paid		-37.7	-14.9	-13.8	-5.8	-21.8
Income taxes paid		-12.3	-3.7	-174.7	-9.1	-188.2
Changes in working capital		159.4	67.1	225.2	146.9	162.7
Total cash flows from operating activities		**615.4**	**199.1**	775.3	357.1	906.6
Cash flows from investing activities						
Investment in oil and gas properties		-1,377.9	-474.4	-1,207.3	-548.6	-1,698.4
Investment in other fixed assets		-105.9	-25.5	-19.8	-10.6	-36.2
Disposal of bonds		10.5	–	–	–	–
Investment in subsidiaries		–	–	-3.5	-3.5	-3.5
Share in result in associated company		11.7	11.7	–	–	–
Decommissioning costs paid		-0.9	-0.5	-0.7	0.2	-1.5
Other payments		-0.1	–	-0.4	-0.2	-0.4
Total cash flows from investing activities		**-1,462.6**	**-488.7**	-1,231.7	-562.7	-1,740.0
Cash flows from financing activities						
Changes in long-term receivables		9.8	9.9	3.7	–	3.5
Changes in long-term liabilities		892.9	316.7	474.7	220.6	845.1
Financing fees paid		-20.7	–	–	–	–
Purchase of own shares		-9.8	–	-20.1	-1.7	-20.1
Distributions		-0.1	–	-0.1	–	-0.1
Total cash flows from financing activities		**872.1**	**326.6**	458.2	218.9	828.4
Change in cash and cash equivalents		24.9	37.0	1.8	13.3	-5.0
Cash and cash equivalents at the beginning of the period		82.4	73.1	87.6	80.6	87.6
Currency exchange difference in cash and cash equivalents		4.6	1.8	0.6	-3.9	-0.2
Cash and cash equivalents at the end of the period		**111.9**	**111.9**	90.0	90.0	82.4

Consolidated Statement of Changes in Equity in Summary

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 2013	**0.5**	**411.1**	**770.8**	**1,182.4**	**67.7**	**1,250.1**
Comprehensive income						
Net result	–	–	53.9	53.9	-4.0	49.9
Other comprehensive income	–	-42.6	–	-42.6	-2.6	-45.2
Total comprehensive income	**–**	**-42.6**	**53.9**	**11.3**	**-6.6**	**4.7**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-20.1	–	-20.1	–	-20.1
Total transactions with owners	**–**	**-20.1**	**–**	**-20.1**	**-0.1**	**-20.2**
At 30 September 2013	**0.5**	**348.4**	**824.7**	**1,173.6**	**61.0**	**1,234.6**
Comprehensive income						
Net result	–	–	23.7	23.7	-0.7	23.0
Other comprehensive income	–	9.7		9.7	-0.5	9.2
Total comprehensive income	**–**	**9.7**	**23.7**	**33.4**	**-1.2**	**32.2**
Transactions with owners						
Distributions	–	–	–	–	–	–
Purchase of own shares	–	–	–	–	–	–
Total transactions with owners	**–**	**–**	**–**	**–**	**–**	**–**
At 31 December 2013	**0.5**	**358.1**	**848.4**	**1,207.0**	**59.8**	**1,266.8**
Comprehensive income						
Net result	–	–	8.8	8.8	-3.7	5.1
Other comprehensive income	–	-136.7	–	-136.7	-7.8	-144.5
Total comprehensive income	**–**	**-136.7**	**8.8**	**-127.9**	**-11.5**	**-139.4**
Transactions with owners[1]						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Value of employee services	–	–	0.6	0.6	–	0.6
Total transaction with owners	**–**	**-9.8**	**0.6**	**-9.2**	**-0.1**	**-9.3**
At 30 September 2014	**0.5**	**211.6**	**857.8**	**1,069.9**	**48.2**	**1,118.1**

[1] During the reporting period the Parent Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount. The amounts were recognised against other reserves. In consequence the cancellation of shares did not impact the Company's share capital.

Notes to the Consolidated Financial Statements

Note 1. Revenue MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Crude oil	530.5	117.2	762.0	279.7	997.0
Condensate	2.8	1.0	2.3	0.9	3.4
Gas	90.6	22.4	118.9	33.1	160.0
Net sales of oil and gas	**623.9**	**140.6**	883.2	313.7	1,160.4
Change in under/over lift position	13.8	44.3	-38.0	-54.0	-45.2
Other revenue	12.3	4.3	12.7	4.1	16.8
Revenue	**650.0**	**189.2**	857.9	263.8	1,132.0

Note 2. Production costs MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Cost of operations	72.2	19.7	73.2	20.8	103.0
Tariff and transportation expenses	15.0	5.2	16.6	5.5	21.6
Direct production taxes	2.8	0.9	2.6	0.9	3.4
Change in inventory position	0.5	2.1	-0.1	2.2	-2.0
Other	14.2	-3.5	1.4	—	13.6
	104.7	**24.4**	93.7	29.4	139.6

Note 3. Segment information MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Norway					
Crude oil	446.5	82.1	676.9	240.2	886.6
Condensate	1.7	0.6	1.5	0.7	2.0
Gas	46.6	9.7	73.2	18.7	98.5
Net sales of oil and gas	**494.8**	**92.4**	751.6	259.6	987.1
Change in under/over lift position	14.4	44.8	-37.9	-52.1	-47.0
Other revenue	3.1	0.8	4.2	1.3	5.6
Revenue	**512.3**	**138.0**	717.9	208.8	945.7
Production costs	-63.9	-8.1	-52.4	-14.0	-85.1
Depletion and decommissioning costs	-64.9	-18.5	-89.3	-26.1	-130.2
Exploration costs	-74.2	0.4	-150.6	-17.2	-285.4
Impairment costs of oil and gas properties	—	—	-81.7	—	-81.7
Gross profit	**309.3**	**111.8**	343.9	151.5	363.3

Note 3. Segment information cont. MUSD	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
France					
Crude oil	83.9	35.1	85.0	39.5	110.2
Net sales of oil and gas	**83.9**	**35.1**	85.0	39.5	110.2
Change in under/over lift position	0.1	-0.2	-2.1	-1.9	-0.4
Other revenue	1.3	0.4	1.7	0.6	2.2
Revenue	**85.3**	**35.3**	84.6	38.2	112.0
Production costs	-25.2	-10.4	-27.7	-10.5	-34.3
Depletion and decommissioning costs	-12.8	-4.2	-9.0	-3.0	-12.5
Exploration costs	–	–	-0.1	–	-0.2
Gross profit	**47.3**	**20.7**	47.8	24.7	65.0
Netherlands					
Crude oil	0.1	–	0.1	–	0.2
Condensate	1.1	0.4	0.8	0.2	1.4
Gas	26.0	6.5	32.9	10.1	44.6
Net sales of oil and gas	**27.2**	**6.9**	33.8	10.3	46.2
Change in under/over lift position	-0.7	-0.3	2.0	–	2.2
Other revenue	1.7	0.7	1.3	0.4	1.7
Revenue	**28.2**	**7.3**	37.1	10.7	50.1
Production costs	-12.1	-4.5	-9.8	-3.4	-14.7
Depletion and decommissioning costs	-12.2	-3.9	-11.3	-3.3	-15.0
Exploration costs	-1.0	-0.5	-1.4	-1.4	-1.3
Gross profit	**2.9**	**-1.6**	14.6	2.6	19.1
Indonesia					
Gas	18.0	6.2	12.8	4.3	16.9
Net sales of oil and gas	**18.0**	**6.2**	12.8	4.3	16.9
Other revenue	–	–	–	–	–
Revenue	**18.0**	**6.2**	12.8	4.3	16.9
Production costs	-3.5	-1.4	-3.8	-1.5	-5.0
Depletion and decommissioning costs	-8.5	-3.0	-8.7	-2.9	-11.4
Exploration costs	-54.2	-0.2	-0.2	–	-0.4
Gross profit	**-48.2**	**1.6**	0.1	-0.1	0.1
Other					
Crude oil	–	–	–	–	–
Net sales of oil and gas	–	–	–	–	–
Other revenue	6.2	2.4	5.5	1.8	7.3
Revenue	**6.2**	**2.4**	5.5	1.8	7.3
Production costs	–	–	–	–	-0.5
Depletion and decommissioning costs	–	–	–	–	-0.2
Exploration costs	-0.1	–	-0.5	0.1	-0.5
Impairment costs of oil and gas properties[1]	–	–	-41.7	-41.7	-41.7
Gross profit	**6.1**	**2.4**	-36.7	-39.8	-35.6

[1] Impairment costs of oil and gas properties in 2013 related to Malaysia.

Note 3. Segment information cont. MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Total					
Crude oil	530.5	117.2	762.0	279.7	997.0
Condensate	2.8	1.0	2.3	0.9	3.4
Gas	90.6	22.4	118.9	33.1	160.0
Net sales of oil and gas	**623.9**	**140.6**	883.2	313.7	1,160.4
Change in under/over lift position	13.8	44.3	-38.0	-54.0	-45.2
Other revenue	12.3	4.3	12.7	4.1	16.8
Revenue	**650.0**	**189.2**	857.9	263.8	1,132.0
Production costs	-104.7	-24.4	-93.7	-29.4	-139.6
Depletion and decommissioning costs	-98.4	-29.6	-118.3	-35.3	-169.3
Exploration costs	-129.5	-0.3	-152.8	-18.5	-287.8
Impairment costs of oil and gas properties	–	–	-123.4	-41.7	-123.4
Gross profit	**317.4**	**134.9**	369.7	138.9	411.9

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 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Interest income	0.8	0.2	1.9	0.7	2.4
Foreign currency exchange gain, net	–	–	–	–	–
Guarantee fees	0.4	0.1	0.3	0.1	0.5
Other	0.1	–	0.4	–	0.5
	1.3	**0.3**	2.6	0.8	3.4

Note 5. Finance costs MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Interest expense	11.7	4.9	3.6	1.0	5.1
Foreign currency exchange loss, net	66.8	58.0	33.2	17.4	46.5
Result on interest rate hedge settlement	1.7	0.7	1.0	0.5	1.5
Unwinding of site restoration discount	5.3	1.7	4.5	1.5	5.9
Amortisation of deferred financing fees	9.8	3.7	6.5	2.1	8.7
Loan facility commitment fees	16.9	5.5	13.8	4.2	17.1
Other	0.8	–	0.7	0.3	1.1
	113.0	**74.5**	63.3	27.0	85.9

Note 6. Income tax expense MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Current tax	-258.7	-142.2	-0.3	-31.5	24.7
Deferred tax	404.4	190.3	229.7	127.3	190.4
	145.7	**48.1**	229.4	95.8	215.1

Note 7. Oil and gas properties

MUSD	30 Sep 2014	31 Dec 2013
Norway	3,547.3	2,685.6
France	208.5	224.4
Netherlands	46.5	60.1
Indonesia	68.5	101.7
Russia	538.6	559.1
Malaysia	382.0	189.9
	4,791.4	3,820.8

Note 8. Financial assets

MUSD	30 Sep 2014	31 Dec 2013
Other shares and participations	14.5	22.0
Long-term receivables	–	9.7
Deferred tax	20.5	22.4
Corporate tax	259.8	–
Bonds	–	10.4
Derivative instruments	0.1	3.0
Other	1.2	1.5
	296.1	69.0

Note 9. Receivables and inventories

MUSD	30 Sep 2014	31 Dec 2013
Inventories	33.2	21.2
Trade receivables	54.5	125.8
Underlift	2.3	9.4
Corporate tax	0.8	6.5
Joint venture debtors	16.4	25.2
Derivative instruments	–	3.2
Prepaid expenses and accrued income	40.6	61.7
Other	9.3	26.6
	157.1	279.6

Note 10. Provisions

MUSD	30 Sep 2014	31 Dec 2013
Non-current:		
Site restoration	254.3	241.6
Deferred tax	1,393.2	1,066.0
Long-term incentive plan	1.7	30.8
Derivative instruments	8.4	1.6
Pension	1.3	1.5
Farm-in payment	7.5	–
Other	3.4	3.6
	1,669.8	1,345.1
Current:		
Farm-in payment	48.5	–
Long-term incentive plan	4.1	46.2
Other	10.5	–
	63.1	46.2
	1,732.9	1,391.3

Note 11. Financial liabilities

MUSD	**30 Sep 2014**	31 Dec 2013
Bank loans	2,166.0	1,275.0
Capitalised financing fees	-44.0	-35.9
	2,122.0	1,239.1

Note 12. Current liabilities

MUSD	**30 Sep 2014**	31 Dec 2013
Trade payables	17.5	16.3
Overlift	8.0	29.2
Tax liabilities	2.3	4.3
Joint venture creditors and accrued expenses	391.5	334.5
Other accrued expenses	61.5	39.4
Long-term incentive plan	29.1	—
Derivative instruments	25.6	4.0
Other	5.4	11.5
	540.9	439.2

Note 13. Financial instruments

MUSD

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

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

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

30 September 2014 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
– Other shares and participations	14.1	—	0.4
– Derivative instruments — non-current	—	0.1	—
– Derivative instruments — current	—	—	—
	14.1	**0.1**	**0.4**
Liabilities			
– Derivative instruments — non-current	—	8.4	—
– Derivative instruments — current	—	25.6	—
	–	**34.0**	**–**

Note 13. Financial instruments, cont.
31 December 2013

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

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

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

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

The USD 2.5 billion financing facility, entered into on 25 June 2012 is a revolving borrowing base facility secured against certain cash flows generated by the Group. On 6 February 2014, Lundin Petroleum increased the facility to USD 4.0 billion on similar terms. 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 maturity date of the new bank facility is June 2019 and there is a loan reduction schedule which commences in 2016 and reduces to zero by the final maturity date. In addition, the amount available to borrow under the facility is based upon a net present value calculation of the assets' future cash flows. Based on the reduction schedule and the current availability calculation, part of the current outstanding bank loan balance falls due within five years, at the end of 2017.

Note 14. Adjustment for non-cash related items MUSD	**1 Jan 2014- 30 Sep 2014 9 months**	**1 Jul 2014- 30 Sep 2014 3 months**	1 Jan 2013- 30 Sep 2013 9 months	1 Jul 2013- 30 Sep 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Exploration costs	129.5	0.3	152.8	18.5	287.8
Depletion, depreciation and amortisation	102.1	30.8	121.5	36.5	160.4
Current tax	-258.7	-142.2	-0.3	-31.5	24.7
Deferred tax	404.4	190.3	229.8	127.4	190.4
Impairment of oil and gas properties	–	–	123.4	41.7	123.4
Long-term incentive plan	12.5	1.6	9.3	8.9	9.9
Other[1]	110.6	6534	51.5	21.8	83.5
	500.4	**146.1**	687.9	223.2	880.1

[1] Other adjustments include foreign exchange losses of MUSD 71.8 (MUSD 38.8) for the reporting period.

Parent Company Income Statement in Summary

Expressed in MSEK	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Revenue	**7.6**	**1.0**	0.9	1.0	3.1
General and administration expenses	-109.8	-25.3	-58.1	-27.2	-105.7
Operating profit	**-102.2**	**-24.3**	-57.2	-26.2	-102.6
Result from financial investments					
Finance income	3.0	1.2	2.4	0.7	181.4
Finance costs	-1.9	- 0.1	-1.6	-1.5	-2.7
	1.1	**1.1**	0.8	-0.8	178.7
Profit before tax	**-101.1**	**-23.2**	-56.4	-27.0	76.1
Income tax expense	–	–	–	–	–
Net result	**-101.1**	**-23.2**	-56.4	-27.0	76.1

Parent Company Comprehensive Income Statement in Summary

Expressed in MSEK	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Net result	**-101.1**	**-23.2**	-56.4	-27.0	76.1
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**-101.1**	**-23.2**	-56.4	-27.0	76.1
Attributable to:					
Shareholders of the Parent Company	-101.1	-23.2	-56.4	-27.0	76.1
	-101.1	**-23.2**	-56.4	-27.0	76.1

Parent Company Balance Sheet in Summary

Expressed in MSEK	**30 September 2014**	31 December 2013
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	887.6	17.3
Cash and cash equivalents	2.3	2.6
Total current assets	**889.9**	19.9
TOTAL ASSETS	**8,761.9**	7,891.9
SHAREHOLDERS' EQUITY AND LIABILITIES		
Shareholders' equity including net result for the period	7,650.7	7,814.0
Non-current liabilities		
Provisions	36.6	36.6
Payables to group companies	–	21.6
Total non-current liabilities	**36.6**	58.2
Current liabilities		
Current liabilities	10.8	19.7
Payables to group companies	1,063.8	19.7
Total current liabilities	**1,074.6**	19.7
Total liabilities	**1,111.2**	77,9
TOTAL EQUITY AND LIABILITIES	**8,761.9**	7,891.9
Pledged assets	12,991.0	12,014.5

Parent Company Cash Flow Statement in Summary

Expressed in MSEK	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Cash flow from operations					
Net result	-101.1	-23.2	-56.4	-27.0	76.1
Adjustment for non-cash related items	-0.2	-0.3	0.3	0.3	-18.9
Changes in working capital	184.8	196.8	9.9	-0.3	14.2
Total cash flow from operations	**83.5**	**173.3**	-46.2	-27.0	71.4
Cash flow from investments					
Change in other fixed assets	-0.1	-0.1	–	–	-0.2
Total Cash flow from investments	**-0.1**	**-0.1**	–	–	-0.2
Cash flow from financing					
Change in long-term liabilities	-21.7	-175.6	178.5	35.4	62.2
Purchase of own shares	-62.2	–	-131.9	-11.4	-131.9
Total cash flow from financing	**-83.9**	**-175.6**	46.6	24.0	-69.7
Change in cash and cash equivalents	-0.5	-2.4	0.4	-3.0	1.5
Cash and cash equivalents at the beginning of the period	**2.6**	**4.6**	1.1	4.4	1.1
Currency exchange difference in cash and cash equivalents	0.2	0.1	–	0.1	–
Cash and cash equivalents at the end of the period	**2.3**	**2.3**	1.5	1.5	2.6

Parent Company Statement of Changes in Equity in Summary

Expressed in MSEK	Restricted equity: Share capital	Restricted equity: Statutory reserve	Unrestricted equity: Other reserves	Unrestricted equity: Retained earnings	Unrestricted equity: Total	Total equity
Balance at 1 January 2013	**3.2**	**861.3**	**2,489.4**	**4,515.9**	**7,005.3**	**7,869.8**
Total comprehensive income	**–**	**–**	**–**	**-56.4**	**-56.4**	**-56.4**
Transactions with owners						
Purchase of own shares	–	–	-131.9	–	-131.9	-131.9
Total transactions with owners	**–**	**–**	**-131.9**	**–**	**-131.9**	**-131.9**
Balance at 30 September 2013	**3.2**	**861.3**	**2,357.5**	**4,459.5**	**6,817.0**	**7,681.5**
Total comprehensive income	**–**	**–**	**–**	**132.5**	**132.5**	**132.5**
Transactions with owners						
Purchase of own shares	–	–	–	–	–	–
Total transactions with owners	**–**	**–**	**–**	**–**	**–**	**–**
Balance at 31 December 2013	**3.2**	**861.3**	**2,357.5**	**4,592.0**	**6,949.5**	**7,814.0**
Total comprehensive income	**–**	**–**	**–**	**-101.1**	**-101.1**	**-101.1**
Transactions with owners [1]						
Purchase of own shares	–	–	-62.2	–	-62.2	-62.2
Total transactions with owners	**–**	**–**	**-62.2**	**–**	**-62.2**	**-62.2**
Balance at 30 September 2013	**3.2**	**861.3**	**2,295.3**	**4,490.9**	**6,786.2**	**7,650.7**

[1] During the reporting period the Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount. The amounts were recognised against other reserves. In consequence the cancellation of shares did not impact the Company's share capital.

Key Financial Data

Financial data (MUSD)	**1 Jan 2014-30 Sep 2014 9 months**	**1 Jul 2014-30 Sep 2014 3 months**	1 Jan 2013-30 Sep 2013 9 months	1 Jul 2013-30 Sep 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Revenue[1]	650.0	189.2	857.9	263.8	1,132.0
EBITDA	506.9	157.6	737.7	220.1	955.7
Net result	5.1	4.3	49.9	1.7	72.9
Operating cash flow	804.0	307.0	764.6	266.0	967.9
Data per share (USD)					
Shareholders' equity per share	3.46	3.46	3.79	3.79	3.90
Operating cash flow per share	2.57	0.97	2.47	0.86	3.12
Cash flow from operations per share	1.97	0.63	2.92	2.50	2.92
Earnings per share	0.03	0.02	0.17	0.01	0.25
Earnings per share fully diluted	0.03	0.02	0.17	0.01	0.25
EBITDA per share	1.62	0.49	2.38	0.71	3.08
Dividend per share	–	–	–	–	–
Number of shares issued at period end	311,070,330	311,070,330	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	309,070,330	309,070,330	309,570,330	309,570,330	309,570,330
Weighted average number of shares for the period	312,537,337	315,910,580	310,017,074	309,500,416	310,017,074
Share price					
Quoted price at period end (SEK)	122.10	122.10	138.60	138.60	125.40
Quoted price at period end (CAD)	19.00	19.00	22.40	22.40	19.73
Key ratios					
Return on equity (%)	0	0	4	0	6
Return on capital employed (%)	8	4	17	6	16
Net debt/equity ratio (%)	192	192	69	68	99
Equity ratio (%)	20	20	31	31	29
Share of risk capital (%)	45	45	59	59	53
Interest coverage ratio	17	21	69	73	52
Operating cash flow/interest ratio	60	55	165	167	149
Yield	–	–	–	–	–

[1] The comparatives have been restated for the effect of the adoption of IFRS 11 Joint Arrangements.

Key Ratio Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Financial Information

The financial information relating to the nine month period ended 30 September 2014 has not been subject to review by the auditors of the Company.

Stockholm, 5 November 2014

C. Ashley Heppenstall
President and CEO

The Company will publish the following reports:

- The year end report (January — December 2014) will be published on 4 February 2015
- The three month report (January — March 2015) will be published on 6 May 2015

The AGM will be held on 7 May 2015 in Stockholm, Sweden.

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

Contingent Resources
Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. There is no certainty that it will be commercially viable for the Company to produce any portion of the Contingent Resources. Unless otherwise stated, all contingent resource estimates contained herein are the best estimate ("2C") contingent resources.

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

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

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