Lundin Petroleum

Q3

Report for the NINE MONTHS ended 30 September 2016

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Nine months ended 30 September 2016 (30 September 2015)

- Production of 68.9 Mboepd (30.3 Mboepd)
- Revenue of MUSD 774.0 (MUSD 433.3)
- EBITDA of MUSD 584.7 (MUSD 291.1)
- Operating cash flow of MUSD 667.8 (MUSD 524.3)
- Net result of MUSD 239.8 (MUSD -372.6) including a net foreign exchange gain of MUSD 230.9 (loss of MUSD 378.1)
- Net debt of MUSD 4,307 (31 December 2015: MUSD 3,786)
- 26 percent increase in production in the third quarter of 2016 compared to the second quarter following the Edvard Grieg production ramp-up and increased 15 percent equity in the field following the completion of the transaction with Statoil on 30 June 2016.
- Full year production guidance revised to 70,000—75,000 boepd from 65,000—75,000 boepd and cost of operations per boe guidance lowered to USD 6.50 from USD 7.10.
- Record low cost of operations per boe of USD 5.55 and cash operating costs per boe of USD 7.22 in the third quarter of 2016.
- In August 2016, the operator provided a guidance update on the Johan Sverdrup project announcing reduced capital costs to NOK 99 billion gross for Phase 1 and NOK 140—170 billion gross for Phase 1 and Phase 2 and an increased Phase 1 and Phase 2 production capacity of 660,000 bopd gross. The resource range increased to 1.9—3.0 billion boe.
- Secured new fully committed reserve-based lending facility of USD 5.0 billion.

Third quarter ended 30 September 2016 (30 September 2015)

- Production of 80.4 Mboepd (36.0 Mboepd)
- Revenue of MUSD 317.4 (MUSD 154.2)
- EBITDA of MUSD 253.8 (MUSD 98.7)
- Operating cash flow of MUSD 281.9 (MUSD 177.0)
- Net result of MUSD 173.8 (MUSD -201.6) including a net foreign exchange gain of MUSD 135.8 (loss of MUSD 201.4).

	1 Jan 2016– 30 Sep 2016 9 months	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015— 30 Sep 2015 9 months	1 Jul 2015— 30 Sep 2015 3 months	1 Jan 2015— 31 Dec 2015 12 months
Production in Mboepd	**68.9**	**80.4**	30.3	36.0	32.3
Revenue in MUSD	**774.0**	**317.4**	433.3	154.2	569.3
Net result in MUSD	**239.8**	**173.8**	-372.6	-201.6	-866.3
Net result attributable to shareholders of the Parent Company in MUSD	**243.2**	**174.9**	-369.2	-200.4	-861.7
Earnings/share in USD[1]	**0.76**	**0.51**	-1.19	-0.65	-2.79
Earnings/share fully diluted in USD[1]	**0.75**	**0.51**	-1.19	-0.65	-2.79
EBITDA in MUSD	**584.7**	**253.8**	291.1	98.7	384.7

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
Bn boe	Billion barrels of oil equivalents
Mcf	Thousand cubic feet

Letter to Shareholders

Dear fellow Shareholders,

Our third quarter operational performance has again delivered excellent results driven by a continued strong performance from the Edvard Grieg field and our other main producing assets delivering at or above expectation. We remain firmly on track to achieve our full year production guidance and given the strong performance we are revising our guidance to between 70,000 and 75,000 boepd from between 65,000 and 75,000 boepd. The third quarter average production of 80,400 boepd was a record high for the Company with corresponding cash operating costs falling to USD 7.20 per barrel, a record low for the Company. We expect to maintain strong production and low operating costs going forward given that Edvard Grieg is planned to reach its plateau production of 100,000 boepd by the time the fourth producer comes onstream towards year end.

Strong financial position

It is also very pleasing to see that as a result of our strong production performance and operational efficiency, the addition of the 15 percent interest in the Edvard Grieg field that we acquired from Statoil during the second quarter and a gradual recovery in oil prices, the financial position of the Company is stronger than ever. With around USD 1 billion of liquidity headroom, our balance sheet is able to sustain long term oil prices as low as USD 40 per barrel and still fully fund the Johan Sverdrup Phase 1 development while continuing to invest in an exciting and aggressive organic growth strategy.

Johan Sverdrup positive update

On the development side, Johan Sverdrup continues to progress according to plan with the Phase 1 project execution in excess of 26 percent completed. During the third quarter, we have also seen further crystallisation of Johan Sverdrup cost reductions, increased Phase 1 and Phase 2 production capacities, and increased resources.

Phase 1 costs are now estimated at NOK 99 billion gross, a 20 percent reduction from the plan of development estimate, excluding foreign exchange rate savings. Phase 1 production capacity has increased as a result of debottlenecking studies to 440,000 bopd representing a 27 percent increase from the mid-point of the previous guidance and full field capacity is increased to 660,000 bopd. The resource range has also been revised upwards to between 1.9 and 3.0 billion boe. This is simply an outstanding achievement leading to significant incremental shareholder value given that our full cycle breakeven cost has fallen from USD 30 per boe to USD 26 per boe. We all know big fields tend to get bigger and I believe we are just at the beginning of this trend.

Active exploration and appraisal drilling

On the exploration and appraisal front, we are also very active with the successful completion of the Alta 3 appraisal well during the third quarter delivering very encouraging results and the ongoing Neiden exploration well. This will be followed by the drilling of the Filicudi exploration well during the fourth quarter. All these wells are situated in the southern Barents Sea, a key growth area for the Company where most of our organic growth activities will be focused in the medium term. We are also pleased to announce that our 2017 exploration and appraisal campaign will be a very exciting one encompassing four exploration wells and four appraisal wells with drilling in southern and eastern Barents Sea, the Utsira High area and the Alvheim area.

For the third quarter in a row, it is mission accomplished and never before has the Company been so well positioned for its next growth phase which is forecast to see the Company producing in excess of 120,000 boepd by the time Johan Sverdrup Phase 1 will come onstream at the end of 2019.

To you, fellow shareholders, and the Board, I thank you for your continued support. To my colleagues and management team, a big thank you for an outstanding performance.

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 2 November 2016

Financial Report for the Nine Months Ended 30 September 2016

OPERATIONAL REVIEW

Lundin Petroleum is an independent oil and gas exploration and production company with a principal focus on operations in Norway, with a portfolio of assets in Norway, Malaysia, France, the Netherlands and Russia. Norway represents the majority of Lundin Petroleum's operational activities with production for the nine month period ending 30 September 2016 (reporting period) accounting for 80 percent of total production and with 96 percent of Lundin Petroleum's total reserves as at 1 January 2016.

Reserves and Resources

Lundin Petroleum has 716.2 million barrels of oil equivalent (MMboe) of proven plus probable reserves as at 1 January 2016 as certified by an independent third party. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. The best estimate contingent resources net to Lundin Petroleum amount to 386 MMboe as at 1 January 2016.

Production

Production for the reporting period amounted to 68.9 thousand barrels of oil equivalent per day (Mboepd) (compared to 30.3 Mboepd for the same period in 2015) and was comprised as follows:

Production in Mboepd	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Crude oil					
Norway	49.6	60.6	17.8	19.9	18.6
France	2.6	2.5	2.8	2.6	2.7
Malaysia	8.7	8.9	4.2	8.1	5.5
Total crude oil production	**60.9**	**72.0**	24.8	30.6	26.8
Gas					
Norway	5.7	6.9	2.1	2.0	2.1
Netherlands	1.6	1.5	1.7	1.9	1.8
Indonesia	0.7	–	1.7	1.5	1.6
Total gas production	**8.0**	**8.4**	5.5	5.4	5.5
Total production					
Quantity in Mboe	**18,882.7**	**7,394.5**	8,263.7	3,312.3	11,790.3
Quantity in Mboepd	**68.9**	**80.4**	30.3	36.0	32.3

Norway

Production

Production in Mboepd	WI [1]	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Edvard Grieg	65%[2]	38.6	51.0	–	–	1.4
Alvheim	15%	9.1	9.4	8.1	8.2	7.8
Volund	35%	3.0	2.3	5.2	4.8	4.9
Bøyla	15%	1.8	1.5	2.1	2.4	2.1
Brynhild	90%	2.6	3.0	4.2	6.2	4.2
Gaupe	40%	0.2	0.3	0.3	0.3	0.3
		55.3	**67.5**	19.9	21.9	20.7

[1] Lundin Petroleum's working interest (WI)
[2] WI 50% up to 30 June 2016

Production from the Edvard Grieg field during the reporting period was higher than forecast at 38,600 boepd due to better reservoir performance and uptime than forecast. The Edvard Grieg field commenced production on 28 November 2015 with the initial production flowing from one well with the second and third production wells commencing production in December 2015 and January 2016 respectively. The first two water injection wells have been successfully drilled during the reporting period, with both wells encountering better than expected reservoir sands and pressure communication with the production wells. Both water injection wells are injecting at planned rates. The production capacity from the first three wells has exceeded expectations and the reservoir pressure depletion rate has been more favourable than anticipated. The facilities uptime has also been exceptional for its first production year with an average uptime of 96 percent for the reporting period with the field managing to continue production despite the planned shutdown of the Sage gas terminal as produced gas was re-injected into the reservoir during the period of shutdown. The facilities uptime in the fourth quarter of 2016 is expected to be lower than has been achieved to date due to the field being shut-in for a limited period for the tie-in of the Ivar Aasen field.

The first water injection well, which was drilled in the northwestern part of the field, encountered the top reservoir 23 metres shallow to prognosis with a 26 metres gross oil column. The second water injection well, drilled 1.4 km southwest of the first water injection well, also found the top reservoir shallow to prognosis by 13 metres with a 5 metres gross oil column. The results from these two water injection wells have confirmed that there are additional resources in this part of the field and these will be partly factored into the reserves certification process at year end 2016. In addition to the resource upgrade from the two water injection wells there are plans for a new appraisal well to be drilled in 2017 in the southwestern part of the field, about 2 km south of the second water injection well, that could increase reserves further.

The drilling of the fourth Edvard Grieg production well is ongoing with this well expected to start-up production at the end of 2016 when the field is forecast to achieve its gross plateau production of 100,000 boepd.

A total of 14 development wells are scheduled to be drilled on Edvard Grieg with drilling operations expected to continue into 2018. The total operating cost for the Edvard Grieg field, was USD 7.70 per barrel during the reporting period.

In May 2016, Lundin Petroleum announced that it had entered into an agreement to acquire an additional 15 percent working interest in the Edvard Grieg field from Statoil ASA. The effective date of the transaction is 1 January 2016 and the transaction completed on 30 June 2016. As a result of this transaction, Lundin Petroleum has increased its reserves by 31 MMboe (1 January 2016). The additional production from this transaction has been accounted for from 1 July 2016 and consequently the full year 2016 revised production guidance for Lundin Petroleum was increased from between 60,000 and 70,000 boepd to between 65,000 and 75,000 boepd. Given the continued strong production and operational performance we have revised this guidance upwards to between 70,000 and 75,000 boepd.

Production from the Greater Alvheim area during the reporting period was better than forecast due to better than expected reservoir performance as well as a higher than expected Alvheim FPSO production efficiency of 98 percent, excluding planned shutdown of the Sage gas terminal in the United Kingdom. During August 2016, the terminal was shutdown for planned maintenance for 14 days and consequently the Alvheim FPSO was shut-in during this period. The total operating cost for the Greater Alvheim area was USD 5.44 per barrel during the reporting period. The Greater Alvheim area partners signed a new contract for the Transocean Arctic rig to commence in December 2016 to drill three infill wells and a near-field exploration well.

Net production from the Alvheim field during the reporting period was better than forecast at 9,100 boepd. The reservoir performance continues to be excellent with the most recent infill well, the A5 three-branched production well, commencing production in May 2016 at significantly higher rates than forecast. The outperformance from the A5 well has been offset by certain wells with a high gas-oil ratio having been production constrained due to the gas processing capacity on the Alvheim FPSO. This gas processing constraint has now been mitigated through an upgrade of the Alvheim FPSO gas export compressor, resulting in increased gas handling capacity. The drilling of the Viper and Kobra development wells was completed in June 2016 with expected start-up of these two wells towards the end of 2016. Both wells drilled into excellent reservoir sands with the Kobra well being modified into a dual branch well with one branch completed in a shallower and previously unmapped reservoir section above the main reservoir. The Kobra well was also extended to test the Kobra east exploration prospect with the well successfully encountering an oil-filled reservoir. A further Alvheim infill well is planned to be drilled in 2017.

The Volund field net production during the reporting period was slightly below forecast at 3,000 boepd. Further infill opportunities have been identified on the Volund field and during the reporting period the top holes of two infill wells were successfully drilled by the Transocean Winner rig before it went off hire at the end of July. These two wells will be completed by the Transocean Arctic rig which is scheduled to commence drilling of the infill wells in December 2016 with an expected production start-up in the second half of 2017. One exploration well is planned in 2017 targeting the Volund West prospect which is estimated to contain 7 MMboe of gross unrisked prospective resources.

The Bøyla field net production during the reporting period was slightly ahead of forecast at 1,800 boepd due to good reservoir performance with lower water cut in the wells than expected.

Net production from the Brynhild field during the reporting period was lower than forecast at 2,600 boepd due to a temporary lower well capacity than forecast as well as the water injection system being off-line since August 2016. The water injection system is not anticipated to recommence until early 2017 when a faulty injection pump will have been repaired. Consequently production from Brynhild will be reduced until water injection capacity is re-installed. The Brynhild field achieved an uptime of 70 percent for the reporting period, excluding the planned outage earlier this year. The Haewene Brim FPSO will undergo planned maintenance during the fourth quarter anticipated to last for 20 days and consequently the Brynhild field will be shut-in during this period.

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

Development

Licence	Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
Ivar Aasen Unit	Ivar Aasen	1.385%	Aker BP	May 2013	183 MMboe	Q4 2016	65 Mboepd
Johan Sverdrup Unit	Johan Sverdrup	22.60%	Statoil	August 2015	1.9 — 3.0 Bn boe	Late 2019	660 Mboepd

Ivar Aasen

Ivar Aasen is being developed with a steel jacket platform with the topside facilities consisting of a living quarter and processing facilities with oil, gas and water separation and onward export to the Edvard Grieg platform for final processing and pipeline export. The steel jacket was successfully installed in June 2015 and the pipeline installation between Ivar Aasen and Edvard Grieg was completed during the third quarter of 2015. The topside construction was completed during the reporting period and successfully installed on the jacket in July 2016 with offshore hook-up and commissioning ongoing. Eight development wells have been drilled to date and the Ivar Aasen field is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

The Johan Sverdrup project is progressing on schedule with a majority of Phase 1 contracts now awarded, resulting in estimated total project costs being reduced compared to the original estimates. Phase 1 construction work commenced in 2015 with total project completion standing at 26.4 percent at the end September 2016.

Construction of three steel jackets has commenced at the Kværner yard on the west coast of Norway and of one jacket at the Dragados yard in Spain. Construction of the drilling platform and living quarters, through EPC contracts, is underway in Norway by Aibel and Kværner/KBR respectively and construction of the riser platform and processing platform commenced at Samsung Heavy Industries in Korea during the third quarter 2016 with Aker Solutions being contracted for the procurement and engineering of the riser platform and processing platform. In addition civil engineering works are underway on the onshore power system at Haugsneset in Norway. The pre-drilling of development wells commenced in March 2016 with six development wells being completed to date ahead of schedule.

The contract for the heavy lift installations for three of the topsides has been awarded to Allseas. Odfjell Drilling has been awarded contracts for drilling of the wells. Rosenberg WorleyParsons has been awarded the contracts for the construction of the three bridges linking the platforms and for the construction of two flare booms. In October 2016 the contract for modification work at the Mongstad oil terminal was awarded to Aker Solutions.

At the time of submitting the Phase 1 PDO in February 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). With most of the major contracts now awarded, the latest cost estimate, as released by Statoil during the third quarter 2016, has been reduced to NOK 99 billion (nominal), a reduction of approximately 20 percent. This is based on a fixed project exchange rate of NOK 6 per USD and excludes additional foreign exchange rate savings in US dollar terms. The Phase 1 development is scheduled to start production in late 2019. The original gross production capacity for Phase 1 was estimated at 315,000 to 380,000 bopd. However, debottlenecking measures have concluded that the design processing capacity for Phase 1 will increase to 440,000 bopd with gas processing capacity in addition. It is anticipated that 35 production and injection wells will be drilled to support Phase 1 production, of which 17 wells will be drilled prior to first oil with a semi-submersible rig to facilitate Phase 1 plateau production.

The PDO for Phase 1 also outlines certain concepts for the full field development involving an expected full field gross plateau production level of 660,000 bopd. Statoil provided an update on resources in the third quarter 2016 with gross resources increasing from between 1.7 and 3.0 billion boe to between 1.9 and 3.0 billion boe with 95 percent of the resources being oil.

During the third quarter 2016, Statoil also revised down the full field development costs (Phase 1 and Phase 2) with the previous range of between NOK 160 and 190 billion being revised down to between NOK 140 and 170 billion (real 2016), due to market savings relating to Phase 1 and optimisation of the Phase 2 facilities concept. Phase 2 is expected to start production in 2022.

Appraisal

2016 appraisal well programme

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

During the reporting period Lundin Petroleum successfully completed the drilling and testing of the Alta-3 appraisal well 7220/11-3A, which was a re-entry well from the suspended 7220/11-3 well drilled in 2015. The objective of the Alta-3 re-entry was to deepen the well to further assess the quality of the Permian carbonate reservoirs through water injection tests as well as to conduct a production test in the shallower gas zone. Two injection tests in the carbonate reservoir below the oil-water contact proved good to very good reservoir quality in the Falk and Ørn formations, respectively. A production test in the gas zone in the Lower Triassic reservoir section produced a maximum of 21 million cubic feet of gas per day through a 64/64 inch choke.

The original Alta-3 well encountered a gross hydrocarbon column of 120 metres and all three Alta wells drilled to date have proven pressure communication.

During the reporting period Lundin Petroleum entered into a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig for an extended appraisal and exploration campaign in the southern Barents Sea. The contract encompasses four firm wells and five further well-slot options which can be called at Lundin Petroleum's election and the rig will carry out all of Lundin Petroleum operated wells in the southern Barents Sea for the remaining 2016 drilling campaign as well as for the 2017 campaign.

The 2017 appraisal programme will consist of four appraisal wells with one well being drilled on the western flank of the Edvard Grieg field in PL338 (WI 65%) targeting gross resources of 30 MMboe. The remaining three wells will appraise the Alta/ Gohta discoveries on the Loppa High in the southern Barents Sea with one well being drilled centrally on the Gohta discovery in PL492 (WI 40%) and two wells being drilled on the Alta discovery, one in the south on a mapped extension of the discovery into PL492 (WI 40%) and one centrally on the Alta discovery in PL609 (WI 40%).

Exploration

2016 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL544	16/4-10	January	Fosen	40%	Lundin Petroleum	Dry
Southern Barents Sea						
PL609	Re-enter 7220/6-2-R	October	Neiden	40%	Lundin Petroleum	Ongoing
PL533	n/a	Q4 2016	Filicudi	35%	Lundin Petroleum	

In January 2016, the Lorry well in PL700 in the Norwegian Sea which was spudded in November 2015 was announced as dry. The well failed to encounter the prognosed reservoir.

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

Lundin Petroleum will drill a further six exploration wells offshore Norway from now to the end of 2017 targeting net unrisked prospective resources of over 500 MMboe . The remaining 2016 exploration programme is focused on the Loppa High in the southern Barents Sea with the ongoing Neiden re-entry in PL609 (WI 40%) which is targeting 204 MMboe of gross unrisked resources followed by the Filicudi prospect in PL533 (WI 35%) which is targeting 258 MMboe of gross unrisked resources.

The 2017 exploration programme consists of four wells with one well being drilled west of the Volund field in PL150 (WI 35%) targeting the Volund West prospect with 7 MMboe of gross unrisked resources and one well being drilled on a potential northern extension of the Johan Sverdrup field (WI 22.6%). Two further wells are planned to be drilled in the southern Barents Sea with one well targeting the Hellemobotn or Borselv prospects in PL609C or PL609 (WI 40%) located on-trend north of the Alta discovery with an estimated gross unrisked resource potential of over 300 MMboe on each prospect and the second well targeting one segment of the shallower horizons within the multi-billion barrel gross prospective resource Korpfjell prospect in PL859 (WI 15%) in the southeastern Barents Sea.

Licence awards, transactions and relinquishments
In January 2016, the Ministry of Petroleum and Energy announced the licence awards in the 2015 APA licensing round. Lundin Petroleum was awarded four licences of which two as operator in PL815 and PL830 (both with WI 40%) in addition to two non-operated working interests in PL678SB and PL831 (both with WI 20%). In May 2016 the licence awards in the 23rd licensing round in the southern Barents Sea were announced and Lundin Petroleum was awarded five licences of which three as operator. Lundin Petroleum was awarded two operated licences, PL851 and PL609C (both with WI 40%) in the Loppa High area, one operated licence, PL853 (WI 60%) in the Hoop area and two non-operated licences, PL857 and PL859 (WI 20% and 15% respectively) in the eastern Barents Sea.

During the reporting period, Lundin Petroleum relinquished PL438, PL519, PL544, PL555, PL631, PL673, PL674, PL741 and PL779.

South East Asia

Malaysia

Production

Production in Mboepd	WI	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Bertam	75%	**8.7**	**8.9**	4.2	8.1	5.5

Peninsular Malaysia
Net production from the Bertam field on Block PM307 (WI 75%) during the reporting period was ahead of forecast at 8,700 boepd with an uptime of 99 percent. The Bertam field has been producing from 11 wells as of mid-October 2015 with one additional well, the A15 well, commencing production in June 2016. The A15 well results were better than forecast with production being constrained by facilities limitations. Overall field performance is better than forecast due to better than expected reservoir performance and this outperformance has been partially offset by the shut-in of two production wells during the reporting period in relation to replacement of downhole electrical submersible pumps and for production shut-ins due to moving the drilling rig. The West Prospero drilling rig came off contract towards the end of May 2016.

Several infill drilling targets have been identified on the Bertam field and up to two infill wells are likely to be drilled in 2017.

During the reporting period, Lundin Petroleum relinquished PM308A and PM319.

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

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

FPSO sale
Lundin Petroleum announced on 22 January that it had entered into an agreement to sell the FPSO Bertam to M3nergy Investment Ltd (M3nergy), a wholly owned subsidiary of M3nergy Berhad of Malaysia. The transaction was subject to M3nergy securing financing within a certain timeframe. Given M3nergy has been unable to secure the required financing the agreement to sell the FPSO has been terminated.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Singa	25.9%	**0.7**	–	1.7	1.5	1.6

In April 2016, Lundin Petroleum completed the sale of the business in Indonesia to PT Medco Energi Internasional TBK for a cash consideration of MUSD 22, with an effective date of 1 October 2015. The Indonesian assets sold to Medco include the non-operated interest in the producing Singa gas field. Lundin Petroleum may become entitled to certain contingent payments in respect of the future production from the Singa gas field. Lundin Petroleum ceased reporting the production contribution from Singa as of 28 April 2016.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
France						
– Paris Basin	100%[1]	2.2	2.1	2.3	2.3	2.3
– Aquitaine	50%	0.4	0.4	0.5	0.3	0.4
Netherlands	Various	1.6	1.5	1.7	1.9	1.8
		4.2	**4.0**	4.5	4.5	4.5

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

France
Net production during the reporting period from France was slightly above forecast at 2,600 boepd. Good production performance has been achieved from the Vert La Gravelle field (WI 100%) in the Paris Basin and the fields in the Aquitaine Basin have also performed well during the reporting period.

The Netherlands
Net production for the reporting period from the Netherlands continues to be ahead of forecast at 1,600 boepd. The Slootdorp 6 and 7 wells, drilled in 2015, are now producing through the recently installed permanent production facilities.

The drilling of the K5-F3 development well has been completed and the well was put on production in the third quarter of 2016. During the third quarter of 2016, Lundin Petroleum participated in an onshore exploration well, Langezwaag-3 (WI 7.75%). The well encountered gas and is expected to be put on production during the fourth quarter of 2016. During the fourth quarter of 2016 Lundin Petroleum will also participate in the F3-B106 side-track well.

In 2017, the planned activity involves the drilling of the A6 development well on the offshore E17a-A field (WI 1.2%) and the Nieuwehorne-1 exploration well in the onshore Gorredijk licence (WI 7.75%).

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

Corporate Responsibility

During the reporting period, Lundin Petroleum recorded three incidents among contractors, resulting in a year to date Lost Time Incident Rate of 0.89 per million hours worked and a Total Recordable Incident Rate of 2.22. In February 2016, a tragic fatal accident took place offshore Malaysia when a contractor undertook repair work on the FPSO export hose. A thorough investigation was undertaken and follow-up measures were implemented. Two minor lost time incidents were recorded in France in February and April 2016. No personal safety incident occurred in the third quarter.

In May 2016, Lundin Petroleum issued its first sustainability report based on the Global Reporting Initiative, GRI G4 guidance, providing more qualitative and quantitative sustainability data.

In June 2016, Lundin Petroleum reported to the Carbon Disclosure Project (CDP) on its climate change strategy and 2015 emissions performance.

FINANCIAL REVIEW

Result

The net result for the nine month period ended 30 September 2016 (reporting period) amounted to MUSD 239.8 (MUSD -372.6). The profit for the reporting period was mainly driven by the excellent production performance and a net foreign exchange gain as a result of the weakening US Dollar against the Norwegian Krone and the Euro, partially offset by lower oil prices and expensed exploration costs. The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 243.2 (MUSD -369.2) representing earnings per share of USD 0.76 (USD -1.19).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 584.7 (MUSD 291.1) representing EBITDA per share of USD 1.81 (USD 0.94). Operating cash flow for the reporting period amounted to MUSD 667.8 (MUSD 524.3) representing operating cash flow per share of USD 2.08 (USD 1.70).

Changes in the Group

On 28 April 2016, Lundin Petroleum completed the sale of its Indonesia business, including the non-operated Singa gas field.

Edvard Grieg transaction

The transaction to acquire an additional 15 percent working interest in the Edvard Grieg field and interests in the associated pipeline assets from Statoil ASA with an effective date of 1 January 2016, completed on 30 June 2016. In consideration for the acquisition of the assets, Lundin Petroleum issued 27,580,806 new shares in Lundin Petroleum AB based upon an agreed share price of SEK 138 per share and a SEK/USD exchange rate of 8.098, which equates to a consideration of MUSD 470.0 as at 1 January 2016. The transaction was accounted for at closing in accordance with IFRS3 Business Combinations as required by the amended IFRS11 Joint Arrangements which provides guidance on the accounting for acquisitions of interests in joint operations in which the activity constitutes a business. The production and financial results from the additional working interest are being reflected from 1 July 2016.

A summary of the net assets acquired at closing is shown in the table below:

Expressed in MUSD	30 June 2016
Assets	
Oil and gas properties	454.9
Goodwill	127.1
Cash	31.0
Total Assets Acquired	**613.0**
Liabilities	
Deferred tax	114.0
Site restoration provision	24.2
Working capital	10.3
Total Liabilities Acquired	**148.5**
Net Assets Acquired	**464.5**

Note: the numbers in the table above are subject to finalisation adjustments

In accordance with the Norwegian Petroleum Tax Act, the consideration paid is on an after tax basis and the remaining tax balances were transferred from Statoil ASA to Lundin Petroleum. Lundin Petroleum is therefore not entitled to a tax deduction for the consideration paid over and above the tax values transferred. In accordance with IAS12 Income Taxes, a deferred tax liability for an amount of MUSD 127.1 was recognised on the difference between the assigned fair values and the related tax base as at 30 June 2016, and the offsetting accounting entry is to goodwill. The goodwill forms part of the impairment testing of the Edvard Grieg field going forward.

In addition, Lundin Petroleum transferred 2 million treasury shares and issued 1,735,309 new shares to Statoil ASA in exchange for a cash consideration of MSEK 544.1 (MUSD 64.1).

Revenue

Revenue for the reporting period amounted to MUSD 774.0 (MUSD 433.3) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 738.1 (MUSD 425.4). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 39.47 (USD 53.12) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 41.88 (USD 55.31) per barrel.

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

Sales Average price per boe expressed in USD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	13,617.9	5,216.7	4,939.9	2,101.7	5,939.4
– *Average price per boe*	*40.51*	*44.29*	*54.86*	*49.53*	*52.97*
France					
– Quantity in Mboe	719.3	196.5	768.4	217.2	971.4
– *Average price per boe*	*42.03*	*45.61*	*56.31*	*46.10*	*52.07*
Netherlands					
– Quantity in Mboe	1.2	0.6	1.2	0.6	1.2
– *Average price per boe*	*33.82*	*37.09*	*50.42*	*49.90*	*50.20*
Malaysia					
– Quantity in Mboe	1,993.9	669.6	842.8	620.1	1,455.6
– *Average price per boe*	*42.79*	*46.64*	*52.49*	*48.05*	*48.92*
Total crude oil sales					
– Quantity in Mboe	**16,332.3**	**6,083.4**	6,552.3	2,939.6	8,367.6
– Average price per boe	***40.85***	***44.60***	*54.73*	*48.96*	*52.16*
Gas and NGL sales					
Norway					
– Quantity in Mboe	1,693.6	653.0	569.7	177.9	745.7
– *Average price per boe*	*28.43*	*26.36*	*46.67*	*43.39*	*44.21*
Netherlands					
– Quantity in Mboe	439.2	142.2	473.9	170.1	633.3
– *Average price per boe*	*25.74*	*25.80*	*40.65*	*38.79*	*38.88*
Indonesia					
– Quantity in Mboe	178.2	–	412.7	130.1	527.7
– *Average price per boe*	*52.02*	–	*50.85*	*50.73*	*50.99*
Total gas and NGL sales					
– Quantity in Mboe	**2,311.0**	**795.2**	1,456.3	478.1	1,906.7
– Average price per boe	***29.74***	***26.26***	*45.90*	*43.75*	*44.31*
Total sales					
– Quantity in Mboe	**18,643.3**	**6,878.6**	8,008.6	3,417.7	10,274.3
– Average price per boe	***39.47***	***42.48***	*53.12*	*48.23*	*50.71*

The table above excludes 47,449 barrels of crude oil purchased from outside the Group by Lundin Petroleum Marketing SA and sold to the market.

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 19.4 (charge of MUSD 7.7) in the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 16.5 (MUSD 15.6) for the reporting period and included Bertam FPSO lease income, a quality differential compensation on Alvheim blended crude, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 169.2 (MUSD 114.6) and are detailed in the table below.

Production costs	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cost of operations					
– In MUSD	124.8	41.1	88.3	32.5	121.1
– In USD per boe	*6.61*	*5.55*	*10.68*	*9.80*	*10.27*
Tariff and transportation expenses					
– In MUSD	29.9	11.4	8.1	2.3	11.8
– In USD per boe	*1.59*	*1.55*	*0.99*	*0.70*	*1.00*
Royalty and direct production taxes					
– In MUSD	2.5	0.9	2.6	1.1	3.5
– In USD per boe	*0.13*	*0.12*	*0.31*	*0.33*	*0.29*
Cash operating costs					
– In MUSD	**157.2**	**53.4**	99.0	35.9	136.4
– In USD per boe	***8.33***	***7.22***	*11.98*	*10.83*	*11.56*
Change in inventory position					
– In MUSD	-4.0	-2.4	-5.8	-0.3	-12.6
– In USD per boe	*-0.21*	*-0.33*	*-0.70*	*-0.10*	*-1.07*
Other					
– In MUSD	16.0	4.9	21.4	14.5	26.5
– In USD per boe	*0.85*	*0.66*	*2.59*	*4.37*	*2.25*
Total production costs					
– In MUSD	**169.2**	**55.9**	114.6	50.1	150.3
– In USD per boe	***8.97***	***7.55***	*13.87*	*15.10*	*12.74*

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

The total cost of operations for the reporting period was MUSD 124.8 (MUSD 88.3). The increase compared to the same period last year is due to the contribution of the Edvard Grieg field which commenced production in November 2015. The total cost of operations excluding operational projects amounted to MUSD 111.7 (MUSD 73.5).

The cost of operations per barrel for the reporting period amounted to USD 6.61 (USD 10.68) including operational projects and USD 5.92 (USD 8.89) excluding operational projects. The cost of operations per barrel for the full year is expected to average USD 6.50 including operational projects and USD 5.85 excluding operational projects (the previous guidance given at the second quarter was USD 7.10 and USD 6.35 respectively).

Tariff and transportation expenses for the reporting period amounted to MUSD 29.9 (MUSD 8.1). The increase compared to the same period last year is mainly due the impact of the Edvard Grieg field.

Other costs amounted to MUSD 16.0 (MUSD 21.4) and mainly related to the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price curve at the end of 2015 an asset was recognised as at 31 December 2015. This asset is being charged to the income statement over the remaining term of the arrangement.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 334.9 (MUSD 176.6) and are detailed in Note 3. The depletion costs associated with oil and gas properties amounted to MUSD 334.9 (MUSD 176.6) at an average rate of USD 17.74 (USD 21.38) per barrel. The higher depletion costs for the reporting period compared to the same period last year is due to the depletion charge associated with the Edvard Grieg field, partly offset by a lower Brynhild field depletion rate following the impairment of the carrying value at the end of 2015.

Depletion of other assets amounted to MUSD 23.4 (MUSD 16.5) for the reporting period and related to the Bertam FPSO which was depreciated from April 2015.

Exploration costs

Exploration costs expensed in the income statement for the reporting period amounted to MUSD 70.3 (MUSD 116.3) 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 57.8 were expensed and mainly related to the unsuccessful exploration wells that were drilled in PL700 (Lorry) and PL544 (Fosen). In addition, exploration costs were expensed relating to Malaysia of MUSD 13.1 following the drilling of the unsuccessful Bambazon and Maligan wells in SB307/308. There were no significant exploration costs expensed during the third quarter of 2016.

Other cost of sales

Other cost of sales for the reporting period amounted to MUSD 2.1 (MUSD —) and related to the purchase of crude oil from a third party and marketed by the Group along with its own crude.

Sale of assets

Sale of assets amounted to a charge of MUSD 3.5 (MUSD —) for the reporting period. The reported charge related to the disposal of the Indonesian business which completed on 28 April 2016. The effective date of the deal was 1 October 2015 for a cash consideration of MUSD 22.

General, administrative and depreciation expenses

The general administrative and depreciation expenses for the reporting period amounted to MUSD 21.3 (MUSD 31.2) which included a charge of MUSD 3.4 (MUSD 5.9) in relation to the Group’s long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the reporting period amounted to MUSD 3.4 (MUSD 3.5).

Finance income

Finance income for the reporting period amounted to MUSD 231.7 (MUSD 1.7) and is detailed in Note 4.

The net foreign currency exchange gain for the reporting period amounted to MUSD 230.9 (loss of MUSD 378.1). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group’s reporting entities. The US Dollar weakened against the Euro during the reporting period resulting in a net foreign currency exchange gain on the US Dollar denominated external loan which is borrowed by a subsidiary using Euro as functional currency. In addition, the Norwegian Krone strengthened against the Euro during the reporting period, generating a net foreign currency exchange gain on an intercompany loan balance denominated in Norwegian Krone. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar and for the reporting period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 31.3 (MUSD 108.5).

Finance costs

Finance costs for the reporting period amounted to MUSD 177.4 (MUSD 455.2) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 106.8 (MUSD 47.0) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 14.4 (MUSD 31.4) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense has increased compared to the same period last year due to the increased borrowings to fund the capital expenditure. The result on interest rate hedge settlements amounted to a loss of MUSD 14.8 (MUSD 5.3) and increased compared to the same period last year due to the higher fixed interest rate that was hedged in 2016.

The amortisation of the deferred financing fees amounted to MUSD 38.1 (MUSD 9.3) for the reporting period and related to the expensing of the fees incurred in establishing the new group financing facility and the Norwegian exploration refund facility over the period of usage of the facilities. In addition, the unamortised portion of the capitalised financing fees incurred in establishing the previous financing facilities and the short term revolving credit facility were expensed during the second quarter of 2016 and amounted to MUSD 22.3.

Tax

The overall tax credit for the reporting period amounted to MUSD 36.2 (MUSD 102.8).

The current tax credit for the reporting period amounted to MUSD 65.1 (MUSD 205.5) which included MUSD 64.3 (MUSD 208.9) relating to the tax refund on Norwegian exploration and appraisal expenditure.

The deferred tax charge for the reporting period amounted to MUSD 28.9 (MUSD 102.7) and included a deferred tax credit of MUSD 10.5 related to the expensed capitalised financing fees in the second quarter of 2016.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 and 78 percent. The effective tax rate for the reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange gain and Malaysian exploration costs, and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -3.4 (MUSD -3.4) 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 5,191.3 (MUSD 4,015.4) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway	619.1	232.2	661.7	180.1	880.7
Malaysia	15.4	-0.8	134.7	30.2	130.1
France	1.9	0.4	15.9	1.5	16.9
Netherlands	2.1	0.6	2.0	0.3	2.7
Indonesia	0.1	–	-0.6	0.1	-1.1
	638.6	**232.4**	813.7	212.2	1,029.3

An amount of MUSD 619.1 (MUSD 661.7) of development expenditure was incurred in Norway during the reporting period, primarily on the Johan Sverdrup and Edvard Grieg field developments. In Malaysia, MUSD 15.4 (MUSD 134.7) was incurred during the reporting period primarily on the Bertam field A15 development well.

Exploration and appraisal expenditure in MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway	90.3	31.8	268.7	99.7	370.2
Malaysia	20.6	3.2	7.5	2.9	33.3
France	0.3	0.1	0.4	–	0.4
Russia	0.9	0.3	4.1	0.5	5.3
Indonesia	–	–	3.1	0.4	3.1
Netherlands	0.1	-0.2	1.4	0.2	1.5
	112.2	**35.2**	285.2	103.7	413.8

Exploration and appraisal expenditure of MUSD 90.3 (MUSD 268.7) was incurred in Norway during the reporting period, primarily on the Alta-3 appraisal well in PL609 drilled during the third quarter of 2016, the Fosen well in PL544 and the Lorry well in PL700. In Malaysia, MUSD 20.6 (MUSD 7.5) was incurred during the reporting period mainly on the Bambazon and Maligan wells in SB307/308.

In addition, MUSD 454.9 was added to the oil and gas properties at 30 June 2016 and related to the additional 15 percent of the Edvard Grieg field acquired from Statoil.

Other tangible fixed assets amounted to MUSD 175.6 (MUSD 204.3) and included the accounting book value of the Bertam FPSO.

Goodwill associated with the accounting for the Edvard Grieg transaction amounted to MUSD 127.1 (MUSD —) and is described in the section Edvard Grieg transaction above.

Financial assets amounted to MUSD 6.8 (MUSD 10.7) and are detailed in Note 8. Other shares and participations amounted to MUSD 6.3 (MUSD 4.1) and related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income.

Deferred tax assets amounted to MUSD 15.7 (MUSD 13.4) and are mainly related to Malaysia following the impairment of the Bertam field at year end 2015 resulting in the depreciable tax pool value being higher than the accounting book value.

Derivative instruments amounted to MUSD 26.3 (MUSD —) and related to the marked-to-market gain on the outstanding currency hedges due to be settled after twelve months.

Other non-current assets amounted to MUSD 67.2 (MUSD —) and related to the Norwegian corporate tax refund in respect of the current year which will be received in November 2017.

Current assets

Inventories amounted to MUSD 63.5 (MUSD 45.6) and included both hydrocarbon inventories and well and operational supplies mainly held in Norway and Malaysia.

Trade and other receivables amounted to MUSD 240.8 (MUSD 159.3) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 103.4 (MUSD 35.2) and included two Edvard Grieg cargoes that were invoiced at 30 September 2016. Underlift amounted to MUSD 49.4 (MUSD 26.5) and was mainly attributable to a net underlift position on the Norwegian producing fields. Joint operations debtors relating to various joint venture receivables amounted to MUSD 49.3 (MUSD 48.4). Prepaid expenses and accrued income amounted to MUSD 27.6 (MUSD 29.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 8.7 (MUSD 14.7) and related to marked-to-market valuation of the arrangement where the share of the Brynhild field operating cost varies with the oil price. Other current assets amounted to MUSD 2.4 (MUSD 5.0) and included VAT and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 15.8 (MUSD —) and related to the marked-to-market gain on the outstanding currency hedges due to be settled within twelve months.

Current tax assets amounted to MUSD 286.4 (MUSD 264.7) of which MUSD 286.1 related to the Norwegian corporate tax refund in respect of 2015 which will be received in November 2016.

Cash and cash equivalents amounted to MUSD 48.8 (MUSD 71.9). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,996.7 (MUSD 3,834.8) and are detailed in Note 11. Bank loans amounted to MUSD 4,105.0 (MUSD 3,858.0) and related to the outstanding loan under the Group’s reserve-based lending facility. Capitalised financing fees relating to the establishment costs of the financing facilities, including the Norwegian exploration refund facility, amounted to MUSD 108.3 (MUSD 23.2) and are being amortised over the period of usage of the financing facilities.

Provisions amounted to MUSD 471.1 (MUSD 379.9) and are detailed in Note 12. The provision for site restoration amounted to MUSD 459.7 (MUSD 368.2) and related to future decommissioning obligations. The provision has increased during the reporting period due to additions relating to the Norwegian development projects and by MUSD 24.2 relating to the additional 15 percent of the Edvard Grieg field acquired at 30 June 2016. Farm-in payment amounted to MUSD 4.8 (MUSD 4.6) and related to a provision for payments towards historic costs based on production milestones on Block PM307, Malaysia.

Deferred tax liabilities amounted to MUSD 725.7 (MUSD 542.6) of which MUSD 592.8 (MUSD 407.9) related to Norway and included a net deferred tax liability of MUSD 114.0 related to the additional 15 percent of Edvard Grieg. The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

Derivative instruments amounted to MUSD 27.4 (MUSD 48.4) and related to the marked-to-market loss on the outstanding interest rate hedges due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 33.2 (MUSD 32.2) and mainly represent the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities
Financial liabilities amounted to MUSD 250.9 (MUSD —) and represent the amount drawn under the Norwegian exploration refund facility against the Norwegian exploration tax refund in respect of 2015. The short loan will be repaid in November 2016 when the tax refund is received.

Trade and other payables amounted to MUSD 297.0 (MUSD 349.9) and are detailed in Note 13. Deferred revenue amounted to MUSD 15.9 (MUSD 20.2) and represented a payment advanced by the buyer under the Alvheim Blend oil sales contract. Once the buyer lifts the oil, the liability will be reversed and the revenue will be recognised in the income statement. Joint operations creditors and accrued expenses amounted to MUSD 249.1 (MUSD 271.5) and related mainly to the development and drilling activity in Norway. Other accrued expenses amounted to MUSD 15.9 (MUSD 23.7) and other current liabilities amounted to MUSD 5.5 (MUSD 11.4).

Derivative instruments amounted to MUSD 22.6 (MUSD 66.1) and related to the marked-to-market loss on the outstanding interest rate hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 4.3 (MUSD 4.8) and related to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

Parent Company
The business of the Parent Company is investment in and management of oil and gas assets. The net result for the Parent Company amounted to MSEK -55.8 (MSEK -55.9) for the reporting period.

The result included general and administrative expenses of MSEK 57.2 (MSEK 67.9) and net finance costs of MSEK 1.5 (net finance income of MSEK 3.6).

On 30 June 2016, following 2016 EGM resolutions, Lundin Petroleum AB issued 27,580,806 new shares to Statoil ASA as part of the Edvard Grieg transaction. In addition, the Company also issued 1,735,309 new shares and transferred 2 million treasury shares held to Statoil ASA in exchange for a cash consideration of MSEK 544.1 based upon a share price of SEK 145.66 per share. These three share transactions increased the share capital/premium of the Company by an amount of MSEK 4,533.8.

Following the sale of the 2 million treasury shares to Statoil ASA, the Company does not hold any own shares at 30 September 2016.

Pledged assets of MSEK 9,510.2 (MSEK 3,569.7) relate to the accounting value of the pledge of the shares in respect of the financing facility entered into by its fully-owned subsidiary Lundin Petroleum BV, see also the Liquidity section below.

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

Since 30 June 2016, the Group has sold oil and related products to the Statoil group on an arm's-length basis amounting to MUSD 61.1.

The Group received MUSD 0.2 (MUSD 0.3) from related parties for the provision of office and other services. The Group paid MUSD 0.3 (MUSD 0.2) to related parties in respect of services received.

Liquidity
In February 2016, Lundin Petroleum replaced its existing USD 4.0 billion lending facility, which was due to reduce in availability from June 2016 and mature in 2019, with a committed seven year senior secured reserve-based lending facility of up to USD 5.0 billion, with an initial committed amount of USD 4.3 billion. The committed amount has subsequently been increased to USD 5.0 billion. The financing facility is a reserve-based lending facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields and fields under development at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 30 September 2016 was MUSD 1,103.2 (MUSD 422.9) equivalent and represented the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above.

In April 2015, Lundin Petroleum entered into a NOK 4.5 billion Norwegian exploration refund facility with ten international banks. The facility is secured against the tax refunds generated from Lundin Norway's exploration and appraisal activities on the Norwegian Continental Shelf and extends until the end of 2016. Following the receipt of the 2014 Norwegian exploration tax refund in December 2015, the facility size was reduced to NOK 2.15 billion. As at 30 September 2016, the amount outstanding under the exploration refund facility was NOK 2.02 billion and this amount will be repaid in November 2016 from the 2015 exploration tax refund receipt and the facility cancelled.

In March 2016, Lundin Petroleum entered into a six month revolving credit facility (RCF) of MUSD 300 with the option to extend by a further three months. Following the increased commitments under the Group's USD 5.0 billion reserve-based lending facility and the completion of the Edvard Grieg transaction, the RCF was cancelled effective 30 June 2016.

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 2016 was MUSD 10.5.

Subsequent Events

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

Share Data

Lundin Petroleum AB's issued share capital amounted to SEK 3,478,713 represented by 340,386,445 shares with a quota value of SEK 0.01 each (rounded off).

Remuneration

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

Unit Bonus Plan

The number of units relating to the awards made in 2014, 2015 and 2016 under the Unit Bonus Plan outstanding as at 30 September 2016 were 117,433, 277,928 and 360,099 respectively.

Performance Based Incentive Plan

The AGM 2016 resolved a long-term performance based incentive plan in respect of Group management and a number of key employees. The plan is effective from 1 July 2016 and the 2016 award is accounted for from the second half of 2016. The total number of awards made in respect of 2016 was 530,503 and the awards vest over three years from 1 July 2016 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 89.30 using an option pricing model.

The 2015 plan is effective from 1 July 2015 and the total outstanding number of awards made in respect of 2015 was 694,011 which vest over three years from 1 July 2015 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 91.40.

The 2014 plan is effective from 1 July 2014 and the total outstanding number of awards made in respect of 2014 was 602,554 which vest over three years from 1 July 2014 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 81.40.

Accounting Policies

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

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

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

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

Risks and Risk Management

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

A detailed analysis of Lundin Petroleum's strategic, operational, financial and external risks and mitigation of those risks through risk management is described in Lundin Petroleum's 2015 Annual Report.

Derivative financial instruments

In September 2016, Lundin Petroleum entered into additional forward currency hedges to meet part of its future NOK capital requirements including additional hedging relating to the Johan Sverdrup field development. At 30 September 2016, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 997.8	MUSD 118.5	NOK 8.42:USD 1	Oct 2016 – Dec 2016
MNOK 3,492.6	MUSD 423.6	NOK 8.25:USD 1	Jan 2017 – Dec 2017
MNOK 3,493.0	MUSD 424.2	NOK 8.23:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

At 30 September 2016, Lundin Petroleum had also entered into the following interest rate hedge contracts as follows:

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

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

Exchange Rates

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

	30 Sep 2016		30 Sep 2015		31 Dec 2015	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.4087	8.0517	7.9077	8.5017	8.0637	8.8090
1 USD equals Euro	0.8962	0.8959	0.8973	0.8926	0.9012	0.9185
1 USD equals Rouble	68.4272	63.1789	57.7152	65.3768	61.2881	74.1009
1 USD equals SEK	8.3997	8.6202	8.4089	8.3980	8.4303	8.4408

Consolidated Income Statement

Expressed in MUSD	Note	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Revenue	1	**774.0**	**317.4**	433.3	154.2	569.3
Cost of sales						
Production costs	2	-169.2	-55.9	-114.6	-50.1	-150.3
Depletion and decommissioning costs		-334.9	-135.0	-176.6	-78.1	-260.6
Depletion of other assets		-23.4	-7.8	-16.5	-8.3	-23.7
Exploration costs		-70.3	-1.4	-116.3	-9.4	-184.1
Other cost of sales		-2.1	-2.1	–	–	–
Impairment costs of oil and gas properties		–	–	–	–	-737.0
Gross profit/loss	3	**174.1**	**115.2**	9.3	8.3	-786.4
Sale of assets		-3.5	–	–	–	–
General, administration and depreciation expenses		-21.3	-6.7	-31.2	-6.8	-39.5
Operating profit/loss		**149.3**	**108.5**	-21.9	1.5	-825.9
Net financial items						
Finance income	4	231.7	136.0	1.7	0.4	7.4
Finance costs	5	-177.4	-51.8	-455.2	-230.2	-617.9
		54.3	**84.2**	-453.5	-229.8	-610.5
Profit/loss before tax		**203.6**	**192.7**	-475.4	-228.3	-1,436.4
Income tax	6	36.2	-18.9	102.8	26.7	570.1
Net result		**239.8**	**173.8**	-372.6	-201.6	-866.3
Attributable to:						
Shareholders of the Parent Company		243.2	174.9	-369.2	-200.4	-861.7
Non-controlling interest		-3.4	-1.1	-3.4	-1.2	-4.6
		239.8	**173.8**	-372.6	-201.6	-866.3
Earnings per share – USD[1]		0.76	0.51	-1.19	-0.65	-2.79
Earnings per share fully diluted – USD[1]		0.75	0.51	-1.19	-0.65	-2.79

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	1 Jan 2016– 30 Sep 2016 9 months	1 Jul 2016– 30 Sep 2016 3 months	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Net result	**239.8**	**173.8**	-372.6	-201.6	-866.3
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	22.0	5.6	-67.0	-49.4	-81.7
Cash flow hedges	109.5	44.2	1.3	-17.2	6.9
Available-for-sale financial assets	1.8	0.6	-2.8	-2.2	-3.7
Other comprehensive income, net of tax	**133.3**	**50.4**	-68.5	-68.8	-78.5
Total comprehensive income	**373.1**	**224.2**	-441.1	-270.4	-944.8
Attributable to:					
Shareholders of the Parent Company	372.6	224.8	-435.2	-265.0	-934.8
Non-controlling interest	0.5	-0.6	-5.9	-5.4	-10.0
	373.1	**224.2**	-441.1	-270.4	-944.8

Consolidated Balance Sheet

Expressed in MUSD	Note	30 September 2016	31 December 2015
ASSETS			
Non-current assets			
Oil and gas properties	7	5,191.3	4,015.4
Other tangible fixed assets		175.6	204.3
Goodwill		127.1	–
Financial assets	8	6.8	10.7
Deferred tax assets		15.7	13.4
Derivative instruments	14	26.3	–
Other non-current assets	9	67.2	–
Total non-current assets		**5,610.0**	4,243.8
Current assets			
Inventories		63.5	45.6
Trade and other receivables	10	240.8	159.3
Derivative instruments	14	15.8	–
Current tax assets		286.4	264.7
Cash and cash equivalents		48.8	71.9
Total current assets		**655.3**	541.5
TOTAL ASSETS		**6,265.3**	4,785.3
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		410.9	-498.2
Non-controlling interest		24.6	24.1
Total equity		**435.5**	-474.1
Liabilities			
Non-current liabilities			
Financial liabilities	11	3,996.7	3,834.8
Provisions	12	471.1	379.9
Deferred tax liabilities		725.7	542.6
Derivative instruments	14	27.4	48.4
Other non-current liabilities		33.2	32.2
Total non-current liabilities		**5,254.1**	4,837.9
Current liabilities			
Financial liabilities	11	250.9	–
Trade and other payables	13	297.0	349.9
Derivative instruments	14	22.6	66.1
Current tax liabilities		0.9	0.7
Provisions	12	4.3	4.8
Total current liabilities		**575.7**	421.5
Total liabilities		**5,829.8**	5,259.4
TOTAL EQUITY AND LIABILITIES		**6,265.3**	4,785.3

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cash flows from operating activities					
Net result	239.8	173.8	-372.6	-201.6	-866.3
Adjustments for:					
Exploration costs	70.3	1.4	116.3	9.4	184.1
Depletion, depreciation and amortisation	361.7	143.9	196.7	87.8	286.9
Impairment of oil and gas properties	–	–	–	–	737.0
Current tax	-65.1	-22.4	-205.5	-72.7	-280.6
Deferred tax	28.9	41.3	102.7	46.0	-289.5
Long-term incentive plans	9.3	2.5	11.6	1.8	15.2
Foreign currency exchange	-262.2	-133.2	269.6	172.6	374.6
Interest expense	106.8	33.2	47.0	19.2	71.3
Capitalised financing fees	38.1	6.0	9.3	3.2	12.4
Other	21.0	4.5	25.1	11.9	28.5
Interest received	0.5	0.1	0.4	0.1	6.1
Interest paid	-114.5	-39.4	-77.3	-30.5	-110.1
Income taxes paid / received	4.2	1.1	0.2	0.1	335.6
Changes in working capital	46.9	36.9	-81.1	24.1	-193.7
Total cash flows from operating activities	**485.7**	**249.7**	42.4	71.4	311.5
Cash flows from investing activities					
Investment in oil and gas properties	-750.8	-267.8	-1,098.9	-315.9	-1,443.3
Investment in other fixed assets	1.3	-0.2	-34.5	-2.1	-36.0
Investment in subsidiaries	–	–	-0.1	-0.1	-0.1
Investment in other shares and participations	–	–	-3.7	–	-3.7
Decommissioning costs paid	-10.1	-0.4	-9.6	-5.5	-10.6
Disposal of fixed assets[1]	23.7	–	–	–	–
Other[2]	30.9	-0.1	-0.5	–	-0.5
Total cash flows from investing activities	**-705.0**	**-268.5**	-1,147.3	-323.6	-1,494.2
Cash flows from financing activities					
Changes in long-term liabilities	248.1	40.4	1,075.4	210.6	1,171.0
Financing fees paid	-114.3	-7.3	-3.2	-0.1	-3.3
Issuance of shares/Sale of treasury shares[3]	64.1	–	–	–	–
Total cash flows from financing activities	**197.9**	**33.1**	1,072.2	210.5	1,167.7
Change in cash and cash equivalents	-21.4	14.3	-32.7	-41.7	-15.0
Cash and cash equivalents at the beginning of the period	71.9	34.4	80.5	93.0	80.5
Currency exchange difference in cash and cash equivalents	-1.7	0.1	5.2	1.7	6.4
Cash and cash equivalents at the end of the period	**48.8**	**48.8**	53.0	53.0	71.9

1 Cash received on the sale of the Indonesian business on closing including settlement of net working capital
2 Cash received on closing of the Edvard Grieg transaction with Statoil ASA
3 Cash received on the additional sale of newly issued and treasury shares to Statoil ASA

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent Company					
At 1 January 2015	**0.5**	**8.8**	**422.2**	**431.5**	**34.2**	**465.7**
Comprehensive income						
Net result	–	–	-369.2	-369.2	-3.4	-372.6
Other comprehensive income	–	-66.0	–	-66.0	-2.5	-68.5
Total comprehensive income	**–**	**-66.0**	**-369.2**	**-435.2**	**-5.9**	**-441.1**
Transactions with owners						
Value of employee services	–	–	4.6	4.6	–	4.6
Investment in subsidiaries	–	–	–	–	-0.1	-0.1
Total transactions with owners	**–**	**–**	**4.6**	**4.6**	**-0.1**	**4.5**
At 30 September 2015	**0.5**	**-57.2**	**57.6**	**0.9**	**28.2**	**29.1**
Comprehensive income						
Net result	–	–	-492.5	-492.5	-1.2	-493.7
Other comprehensive income	–	-7.1	–	-7.1	-2.9	-10.0
Total comprehensive income	**–**	**-7.1**	**-492.5**	**-499.6**	**-4.1**	**-503.7**
Transactions with owners						
Value of employee services	–	–	0.5	0.5	–	0.5
Total transaction with owners	**–**	**–**	**0.5**	**0.5**	**–**	**0.5**
At 31 December 2015	**0.5**	**-64.3**	**-434.4**	**-498.2**	**24.1**	**-474.1**
Comprehensive income						
Net result	–	–	243.2	243.2	-3.4	239.8
Other comprehensive income	–	129.4	–	129.4	3.9	133.3
Total comprehensive income	**–**	**129.4**	**243.2**	**372.6**	**0.5**	**373.1**
Transactions with owners						
Issuance of shares / Sale of treasury shares	–	534.1	–	534.1	–	534.1
Value of employee services	–	–	2.4	2.4	–	2.4
Total transaction with owners	**–**	**534.1**	**2.4**	**536.5**	**–**	**536.5**
At 30 September 2016	**0.5**	**599.2**	**-188.8**	**410.9**	**24.6**	**435.5**

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Crude oil	669.4	273.5	358.6	143.9	436.5
Condensate	9.8	4.1	0.4	0.1	0.6
Gas	58.9	16.8	66.4	20.8	83.9
Net sales of oil and gas	**738.1**	**294.4**	425.4	164.8	521.0
Change in under/over lift position	19.4	17.6	-7.7	-17.4	25.6
Other revenue	16.5	5.4	15.6	6.8	22.7
Revenue	**774.0**	**317.4**	433.3	154.2	569.3

Note 2 – Production costs MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cost of operations	124.8	41.1	88.3	32.5	121.1
Tariff and transportation expenses	29.9	11.4	8.1	2.3	11.8
Direct production taxes	2.5	0.9	2.6	1.1	3.5
Change in inventory position	-4.0	-2.4	-5.8	-0.3	-12.6
Other	16.0	4.9	21.4	14.5	26.5
	169.2	**55.9**	114.6	50.1	150.3

Note 3 – Segment information MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Norway					
Crude oil	551.8	231.3	271.0	104.1	314.6
Condensate	9.4	3.9	–	–	–
Gas	38.7	13.3	26.6	7.7	33.0
Net sales of oil and gas	**599.9**	**248.5**	297.6	111.8	347.6
Change in under/over lift position	19.5	17.7	-7.7	-17.2	25.9
Other revenue	0.9	0.3	1.6	0.5	2.0
Revenue	**620.3**	**266.5**	291.5	95.1	375.5
Production costs	-128.6	-46.3	-81.1	-36.4	-104.5
Depletion and decommissioning costs	-270.1	-113.1	-109.3	-44.0	-158.9
Exploration costs	-57.8	-2.0	-115.3	-9.4	-146.5
Impairment costs of oil and gas properties	–	–	–	–	-526.0
Gross profit/loss	**163.8**	**105.1**	-14.2	5.3	-560.4

Notes to the Consolidated Financial Statements

Note 3 – Segment information cont. MUSD	1 Jan 2016– 30 Sep 2016 9 months	1 Jul 2016– 30 Sep 2016 3 months	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
France					
Crude oil	30.2	8.9	43.3	10.0	50.6
Net sales of oil and gas	**30.2**	**8.9**	43.3	10.0	50.6
Change in under/over lift position	0.2	–	–	-0.2	-0.2
Other revenue	0.9	0.3	1.1	0.4	1.5
Revenue	**31.3**	**9.2**	44.4	10.2	51.9
Production costs	-16.5	-4.2	-18.8	-5.2	-25.1
Depletion and decommissioning costs	-10.7	-3.5	-12.0	-3.7	-15.5
Exploration costs	–	–	-0.6	–	-0.6
Gross profit/loss	**4.1**	**1.5**	13.0	1.3	10.7
Netherlands					
Crude oil	–	–	0.1	0.1	0.1
Condensate	0.4	0.2	0.4	0.1	0.6
Gas	10.9	3.5	18.8	6.5	24.0
Net sales of oil and gas	**11.3**	**3.7**	19.3	6.7	24.7
Change in under/over lift position	-0.3	-0.1	–	–	-0.1
Other revenue	1.3	0.3	1.3	0.4	1.8
Revenue	**12.3**	**3.9**	20.6	7.1	26.4
Production costs	-7.7	-2.3	-9.0	-3.2	-12.0
Depletion and decommissioning costs	-7.8	-2.5	-8.2	-2.7	-10.7
Exploration costs	–	–	-0.4	–	-0.7
Gross profit/loss	**-3.2**	**-0.9**	3.0	1.2	3.0
Malaysia					
Crude oil	85.3	31.2	44.2	29.7	71.2
Net sales of oil and gas	**85.3**	**31.2**	44.2	29.7	71.2
Other revenue	11.3	3.8	7.0	3.5	10.8
Revenue	**96.6**	**35.0**	51.2	33.2	82.0
Production costs	-15.0	-3.1	-3.1	-4.7	-4.4
Depletion and decommissioning costs	-46.3	-15.9	-38.0	-24.8	-66.4
Depletion of other assets	-23.4	-7.8	-16.5	-8.3	-23.7
Exploration costs	-13.1	–	–	–	-36.3
Impairment costs of oil and gas properties	–	–	–	–	-191.8
Gross profit/loss	**-1.2**	**8.2**	-6.4	-4.6	-240.6
Indonesia					
Gas	9.3	–	21.0	6.6	26.9
Net sales of oil and gas	**9.3**	**–**	21.0	6.6	26.9
Other revenue	–	–	–	–	–
Revenue	**9.3**	**–**	21.0	6.6	26.9
Production costs	-1.4	–	-2.6	-0.6	-4.3
Depletion and decommissioning costs	–	–	-9.1	-2.9	-9.1
Impairment costs of oil and gas properties	–	–	–	–	-19.2
Gross profit/loss	**7.9**	**–**	9.3	3.1	-5.7

Note 3 – Segment information cont. MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Other					
Crude oil	2.1	2.1	–	–	–
Net sales of oil and gas	**2.1**	**2.1**	–	–	–
Other revenue	2.1	0.7	4.6	2.0	6.6
Revenue	**4.2**	**2.8**	4.6	2.0	6.6
Exploration costs	0.6	0.6	–	–	–
Other cost of sales	-2.1	-2.1	–	–	–
Gross profit/loss	**2.7**	**1.3**	4.6	2.0	6.6

Total					
Crude oil	669.4	273.5	358.6	143.9	436.5
Condensate	9.8	4.1	0.4	0.1	0.6
Gas	58.9	16.8	66.4	20.8	83.9
Net sales of oil and gas	**738.1**	**294.4**	425.4	164.8	521.0
Change in under/over lift position	19.4	17.6	-7.7	-17.4	25.6
Other revenue	16.5	5.4	15.6	6.8	22.7
Revenue	**774.0**	**317.4**	433.3	154.2	569.3
Production costs	-169.2	-55.9	-114.6	-50.1	-150.3
Depletion and decommissioning costs	-334.9	-135.0	-176.6	-78.1	-260.6
Depletion of other assets	-23.4	-7.8	-16.5	-8.3	-23.7
Exploration costs	-70.3	-1.4	-116.3	-9.4	-184.1
Other cost of sales	-2.1	-2.1	–	–	–
Impairment costs of oil and gas properties	–	–	–	–	-737.0
Gross profit/loss	**174.1**	**115.2**	9.3	8.3	-786.4

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

Note 4 – Finance income MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Foreign currency exchange gain, net	230.9	135.8	–	–	–
Interest income	0.5	0.1	0.5	0.2	6.1
Guarantee fees	0.2	0.1	0.7	–	0.7
Other	0.1	–	0.5	0.2	0.6
	231.7	**136.0**	1.7	0.4	7.4

Note 5 – Finance costs MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Interest expense	106.8	33.2	47.0	19.2	71.4
Foreign currency exchange loss, net	–	–	378.1	201.4	507.3
Result on interest rate hedge settlement	14.8	5.2	5.3	1.8	6.9
Unwinding of site restoration discount	10.7	4.0	7.5	2.7	10.0
Amortisation of deferred financing fees	38.1	6.0	9.3	3.2	12.4
Loan facility commitment fees	6.4	3.1	6.7	1.5	7.7
Other	0.6	0.3	1.3	0.4	2.2
	177.4	**51.8**	455.2	230.2	617.9

Notes to the Consolidated Financial Statements

Note 6 – Income tax MUSD	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Current tax	-65.1	-22.4	-205.5	-72.7	-280.6
Deferred tax	28.9	41.3	102.7	46.0	-289.5
	-36.2	**18.9**	-102.8	-26.7	-570.1

Note 7 – Oil and gas properties MUSD	**30 Sep 2016**	31 Dec 2015
Norway	4,200.0	2,987.5
Malaysia	278.3	301.6
France	183.1	187.0
Netherlands	27.2	31.5
Russia	502.7	490.2
Indonesia	–	17.6
	5,191.3	4,015.4

Note 8 – Financial assets MUSD	**30 Sep 2016**	31 Dec 2015
Other shares and participations	6.3	4.1
Brynhild operating cost share	–	5.5
Other	0.5	1.1
	6.8	10.7

Note 9 – Other non-current assets MUSD	**30 Sep 2016**	31 Dec 2015
Corporate tax	67.2	–
	67.2	–

Note 10 – Trade and other receivables MUSD	**30 Sep 2016**	31 Dec 2015
Trade receivables	103.4	35.2
Underlift	49.4	26.5
Joint operations debtors	49.3	48.4
Prepaid expenses and accrued income	27.6	29.5
Brynhild operating cost share	8.7	14.7
Other	2.4	5.0
	240.8	159.3

Note 11 – Financial liabilities

MUSD	30 Sep 2016	31 Dec 2015
Non-current:		
Bank loans	4,105.0	3,858.0
Capitalised financing fees	-108.3	-23.2
	3,996.7	3,834.8
Current:		
Short-term bank loans	250.9	–
	250.9	–
	4,247.6	3,834.8

Note 12 – Provisions

MUSD	30 Sep 2016	31 Dec 2015
Non-current:		
Site restoration	459.7	368.2
Long-term incentive plans	1.8	2.2
Farm-in payment	4.8	4.6
Other	4.8	4.9
	471.1	379.9
Current:		
Long-term incentive plans	4.3	4.8
	4.3	4.8
	475.4	384.7

Note 13 – Trade and other payables

MUSD	30 Sep 2016	31 Dec 2015
Trade payables	10.6	23.1
Deferred revenue	15.9	20.2
Joint operations creditors and accrued expenses	249.1	271.5
Other accrued expenses	15.9	23.7
Other	5.5	11.4
	297.0	349.9

Note 14 – Financial instruments
MUSD

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

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

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

30 September 2016 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	6.3	–	–
Derivative instruments – non-current	–	26.3	–
Derivative instruments – current	–	15.8	–
	6.3	**42.1**	**–**
Liabilities			
Derivative instruments – non-current	–	27.4	–
Derivative instruments – current	–	22.6	–
	–	**50.0**	**–**

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

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

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

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Revenue	**2.9**	**1.0**	8.4	0.9	8.7
General and administration expenses	-57.2	-20.3	-67.9	-17.3	-89.6
Operating profit/loss	**-54.3**	**-19.3**	-59.5	-16.4	-80.9
Net financial items					
Finance income	2.7	0.9	3.7	1.2	4.6
Finance costs	-4.2	–	-0.1	-0.1	-1.8
	-1.5	**0.9**	3.6	1.1	2.8
Profit/loss before tax	**-55.8**	**-18.4**	-55.9	-15.3	-78.1
Income tax	–	–	–	–	–
Net result	**-55.8**	**-18.4**	-55.9	-15.3	-78.1

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Net result	**-55.8**	**-18.4**	-55.9	-15.3	-78.1
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**-55.8**	**-18.4**	-55.9	-15.3	-78.1
Attributable to:					
Shareholders of the Parent Company	-55.8	-18.4	-55.9	-15.3	-78.1
	-55.8	**-18.4**	-55.9	-15.3	-78.1

Parent Company Balance Sheet

Expressed in MSEK	**30 September 2016**	31 December 2015
ASSETS		
Non-current assets		
Shares in subsidiaries	12,256.6	7,871.8
Other tangible fixed assets	0.1	0.2
Receivables to group companies	–	–
Total non-current assets	**12,256.7**	7,872.0
Current assets		
Receivables	19.0	17.5
Cash and cash equivalents	4.5	0.4
Total current assets	**23.5**	17.9
TOTAL ASSETS	**12,280.2**	7,889.9
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	12,260.4	7,782.4
Non-current liabilities		
Provisions	0.4	0.4
Payables to group companies	10.7	100.7
Total non-current liabilities	**11.1**	101.1
Current liabilities		
Current liabilities	8.7	6.4
Total current liabilities	**8.7**	6.4
Total liabilities	**19.8**	107.5
TOTAL EQUITY AND LIABILITIES	**12,280.2**	7,889.9
Pledged assets	**9,510.2**	3,569.7

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2016– 30 Sep 2016 9 months**	**1 Jul 2016– 30 Sep 2016 3 months**	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Cash flow from operations					
Net result	-55.8	-18.4	-55.9	-15.3	-78.1
Adjustment for non-cash related items	15.5	2.4	0.1	–	0.3
Changes in working capital	0.9	5.2	56.1	14.2	-23.8
Total cash flow from operations	**-39.4**	**-10.8**	0.3	-1.1	-101.6
Cash flow from financing					
Change in long-term receivables	10.6	10.6	–	–	–
Change in long-term liabilities	-508.7	-0.8	–	–	100.4
Proceeds from share issues /treasury shares	544.1	–	–	–	–
Total cash flow from financing	**46.0**	**9.8**	–	–	100.4
Change in cash and cash equivalents	6.6	-1.0	0.3	-1.1	-1.2
Cash and cash equivalents at the beginning of the period	**0.4**	**5.5**	1.8	2.9	1.8
Currency exchange difference in cash and cash equivalents	-2.5	–	-0.2	0.1	-0.2
Cash and cash equivalents at the end of the period	**4.5**	**4.5**	1.9	1.9	0.4

Parent Company Statement of Changes in Equity

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 2015	**3.2**	**861.3**	**2,295.3**	**4,700.7**	**6,996.0**	**7,860.5**
Total comprehensive income	**–**	**–**	**–**	**-55.9**	**-55.9**	**-55.9**
Balance at 30 September 2015	**3.2**	**861.3**	**2,295.3**	**4,644.8**	**6,940.1**	**7,804.6**
Total comprehensive income	**–**	**–**	**–**	**-22.2**	**-22.2**	**-22.2**
Balance at 31 December 2015	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**6,917.9**	**7,782.4**
Total comprehensive income	**–**	**–**	**–**	**-55.8**	**-55.8**	**-55.8**
Issuance of shares / sale of treasury shares	0.3	–	4,533.5	–	4,533.5	**4,533.8**
Total transactions with owners	**0.3**	**–**	**4,533.5**	**–**	**4,533.5**	**4,533.8**
Balance at 30 September 2016	**3.5**	**861.3**	**6,828.8**	**4,566.8**	**11,395.6**	**12,260.4**

Key Financial Data

Lundin Petroleum discloses alternative performance measures as part of its financial statements prepared in accordance with ESMA's (European Securities and Markets Authority) guidelines. Definitions of the performance measures are provided under the key ratio definitions below.

Financial data (MUSD)	1 Jan 2016– 30 Sep 2016 9 months	1 Jul 2016– 30 Sep 2016 3 months	1 Jan 2015 – 30 Sep 2015 9 months	1 Jul 2015 – 30 Sep 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Revenue	774.0	317.4	433.3	154.2	569.3
EBITDA	584.7	253.8	291.1	98.7	384.7
Net result	239.8	173.8	-372.6	-201.6	-866.3
Operating cash flow	667.8	281.9	524.3	177.0	699.6
Data per share (USD)					
Shareholders' equity per share	1.21	1.21	0.00	0.00	-1.61
Operating cash flow per share	2.08	0.83	1.70	0.57	2.26
Cash flow from operations per share	1.51	0.73	0.14	0.23	1.01
Earnings per share	0.76	0.51	-1.19	-0.65	-2.79
Earnings per share fully diluted	0.75	0.51	-1.19	-0.65	-2.79
EBITDA per share	1.82	0.75	0.94	0.32	1.24
EBITDA per share – fully diluted	1.81	0.74	0.94	0.32	1.24
Dividend per share	–	–	–	–	–
Number of shares issued at period end	340,386,445	340,386,445	311,070,330	311,070,330	311,070,330
Number of shares in circulation at period end	340,386,445	340,386,445	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period	320,842,368	340,386,445	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period fully diluted	322,271,559	341,815,636	309,854,784	309,854,784	310,019,890
Share price					
Share price at period end (SEK)	146.20	146.20	107.80	107.80	122.60
Key ratios					
Return on equity (%) [1]	-1,243	-901	-151	-81	–
Return on capital employed (%)	2	2	-1	0	-26
Net debt/equity ratio (%) [1]	1,048	1,048	422,975	422,975	–
Equity ratio (%)	7	7	1	1	-10
Share of risk capital (%)	18	18	17	17	1
Interest coverage ratio	1	2	-1	0	-11
Operating cash flow/interest ratio	5	7	10	8	9
Yield	n/a	n/a	n/a	n/a	n/a

[1] As the equity at 31 December 2015 was negative, these ratios have not been calculated.

Key Ratio Definitions

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

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

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

Operating cash flow per share: Operating cash flow divided by the weighted average number of shares for the period.

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

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

Earnings per share fully diluted: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

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

EBITDA per share fully diluted: EBITDA divided by the weighted average number of shares for the period after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

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

Weighted average number of shares for the period fully diluted: The number of shares at the beginning of the period with changes in the number of shares weighted for the proportion of the period they are in issue after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

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

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

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

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

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

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

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

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

Financial Information

The financial information relating to the nine month period ended 30 September 2016 has not been subject to review by the auditors of the Company.

Stockholm, 2 November 2016

Alex Schneiter
President and CEO

The Company will publish the following reports:

- The year end report (January — December 2016) will be published on 1 February 2017.
- The three month report (January — March 2017) will be published on 3 May 2017.

The AGM will be held on 4 May 2017 in Stockholm, Sweden.

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This information is information that Lundin Petroleum AB is required to make public pursuant to the EU Market Abuse Regulation and the Securities Markets Act. The information was submitted for publication, through the contact persons set out above, at 07.00 CET on 2 November 2016.

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.

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