Lundin Petroleum

Q3

Report for the NINE MONTHS ended 30 September 2015

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Nine months ended 30 September 2015 (30 September 2014)

- Production of 30.3 Mboepd (24.4 Mboepd)[1]
- Revenue of MUSD 433.3 (MUSD 650.0)
- EBITDA of MUSD 291.1 (MUSD 506.9)
- Operating cash flow of MUSD 524.3 (MUSD 804.0)
- Net result of MUSD -372.6 (MUSD 5.1) including a net foreign exchange loss of MUSD -378.1
- Net debt of MUSD 3,844 (31 December 2014: MUSD 2,609)
- The Bøyla field, Norway and the Bertam field, Malaysia commenced production in January and April 2015 respectively.
- Edvard Grieg facilities successfully installed, offshore Norway and first oil on track for the fourth quarter 2015.
- The Norwegian Ministry of Petroleum and Energy approved the Plan for Development and Operations (PDO) for Johan Sverdrup Phase 1 in August 2015.
- Alta appraisal wells 7220/11-2 and sidetrack 7220/11-2 A in PL609 in the southern Barents Sea, Norway completed successfully.
- Eight exploration licences awarded in the Norwegian 2014 APA licensing round, six as operator.
- Production licence obtained for the Morskaya field in the Caspian Sea, Russia.
- NOK 4.5 billion financing facility for Norwegian exploration was signed in April 2015.

Third quarter ended 30 September 2015 (30 September 2014)

- Production of 36.0 Mboepd (21.4 Mboepd)[1]
- Revenue of MUSD 154.2 (MUSD 189.2)
- EBITDA of MUSD 98.7 (MUSD 157.6)
- Operating cash flow of MUSD 177.0 (MUSD 307.0), including a net foreign exchange loss of MUSD -201.4
- Net result of MUSD -201.6 (MUSD 4.3)

	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Production in Mboepd[1]	**30.3**	**36.0**	24.4	21.4	23.8
Revenue in MUSD	**433.3**	**154.2**	650.0	189.2	785.2
Net result in MUSD	**-372.6**	**-201.6**	5.1	4.3	-431.9
Net result attributable to shareholders of the Parent Company in MUSD	**-369.2**	**-200.4**	8.8	5.6	-427.2
Earnings/share in USD[2]	**-1.19**	**-0.65**	0.03	0.02	-1.38
Earnings/share fully diluted in USD[2]	**-1.19**	**-0.65**	0.03	0.02	-1.38
EBITDA in MUSD	**291.1**	**98.7**	506.9	157.6	671.3
Operating cash flow in MUSD	**524.3**	**177.0**	804.0	307.0	1,138.5

[1] Excluding production from Russian onshore assets following the sale of the assets in July 2014.
[2] Based on net result attributable to shareholders of the Parent Company.

Definitions

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

Abbreviations

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

Oil related terms and measurements

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

Letter to Shareholders

Dear fellow Shareholders,

It is a great privilege and I am very proud to be writing my first letter to you, our shareholders, as the new President and CEO of Lundin Petroleum, a Company with unique assets, an outstanding team of people, an exciting future growth profile and which has become the leading independent upstream oil company in Europe. On behalf of myself and the whole management team of Lundin Petroleum, I would like to thank my predecessor, Ashley Heppenstall, for an extraordinary job done during his tenure as President and CEO of Lundin Petroleum. Above all I met a great lifelong friend.

Strategy remains unchanged

As I have mentioned several times to investors, Lundin Petroleum's strategy will remain unchanged. The organic growth story will continue and remains our core strategy. I firmly believe in our continued ability to find significant resources at low unit finding costs. In doing so I am confident that we will continue to generate significant value for all our stakeholders. I also believe that for this strategy to remain successful we will need to stay focused and disciplined to maintain our leading competitive edge. In parallel, it is fundamental to our business and growth story to be able to deliver our projects on budget and on schedule and maximise our existing operational efficiency to establish a solid foundation of strong cash flow for the next growth phase of the Company. The ultimate aim will be to position the Company to generate sustainable long term value.

This year has been a very active one for the Company and I am pleased to report that we remain on track to meet our key objective of achieving an exit rate of 75,000 barrels of oil equivalents per day (boepd) by the time Edvard Grieg comes on stream towards the year end. In addition, a major milestone for the Company was achieved back in August with the final approval of the Johan Sverdrup Phase 1 development plan by the Ministry of Petroleum and Energy in Norway. This field is simply unique in terms of size and profitability and will be transformational for the Company by the time first oil is reached at the end of 2019.

Reducing cost levels

Despite a challenging oil price environment we continue to work hard to maintain a robust balance sheet and strong access to liquidity. Capital and operational efficiency remains in the forefront of our minds and we are embracing the low oil price environment as a time of opportunity when it comes to our operations. We will continue our efforts to improve our operational and capital efficiency and reduce costs. Cost levels are reducing and we see clear evidence of that on all fronts; exploration, appraisal, development and production costs. This is an opportune time to tender and award large contracts with the deflationary environment benefitting the Johan Sverdrup project at a time where all major contracts are or are about to be awarded, and I anticipate further cost reductions going forward. Furthermore, this is the perfect time to define our drilling strategy for the years ahead and capitalise on significantly lower rig rates. Lundin Petroleum is very well positioned to benefit from this from early next year as we will have no committed rigs on contract for our exploration and appraisal activities.

Production and development

Our production performance during the third quarter was good with an average of 36,000 boepd achieved. We remain on target to meet our revised production forecast of 32,000 boepd for the full year. The Brynhild field produced ahead of forecast with improved uptime performance during the third quarter. Nevertheless, this asset remains an ongoing concern both in terms of achieving consistent levels of uptime performance and in terms of subsurface performance which we continue to monitor closely. Both the Bøyla field in Norway and the Bertam field in Malaysia came on stream as planned earlier this year with peak production rates being achieved from both fields during the third quarter 2015. Our cost of operations for the reporting period remains low and was below forecast at approximately USD 10.70 per barrel.

We have made good progress with our development projects and I am very encouraged with the performance achieved in the hook up and commissioning phase of the Edvard Grieg field development, which is now 80 percent completed. Furthermore, we have received the formal approval from the Norwegian Petroleum Safety Authority from a health, safety, environmental and operational readiness perspective to commence production. We are firmly on track to achieve first oil by the end of the fourth quarter.

With our Johan Sverdrup development project I am pleased to report that it is progressing according to plan with most of the major contracts now awarded. We also see clear evidence of overall cost reductions compared to the original plan of development estimates. Statoil, the operator of the Johan Sverdrup field, recently announced cost reductions of seven percent. This is a trend that I am confident will continue. We are also making good progress towards the definition of Phase 2 of the Johan Sverdrup development with concept selection expected next year and submission of the Plan of Development in 2017.

Exploration and appraisal

We continue to be very active with our exploration and appraisal activity. Two appraisal wells were completed successfully during the third quarter, the first on the Edvard Grieg field in the Utsira High and the second on the Alta discovery in the Loppa High in the southern Barents Sea. I am pleased with the results of both wells and expect an increase in reserves at the end of the year on the Edvard Grieg field. The results of the 2015 Alta appraisal campaign on the eastern and western flanks of the structure have demonstrated pressure communication with the original discovery well located to the north. Further appraisal on this exciting discovery can be expected in 2016.

Exploration driven organic growth remains a core strategy for Lundin Petroleum. We recently announced the Luno II North discovery on the Utsira High. This together with the previously announced Luno II discovery and the additional resource potential contained in our leading acreage position in this region leads me to believe that more volumes will be developed via our Edvard Grieg facilities.

We will continue to actively explore in our two core areas, Norway and Malaysia. In both countries we will maintain a very focused and disciplined approach. In 2016 we will be active in three areas; the Utsira High and the southern Barents Sea in Norway and the Sabah province offshore Malaysia. I am particularly excited about our position in the southern Barents Sea where we have already made two significant discoveries in addition to two further exploration wells to be drilled this year (Neiden and Ørnen). Given the leading acreage position we have accumulated in the Loppa High where the majority of the discoveries have been made in the last few years, I am confident we will find more resources. In addition, with the upcoming 23rd licensing round, mostly covering acreage in the Barents Sea, I have no doubt in my mind that the area will become a very active exploration region that will undoubtedly lead to commercial development activities. What is even more exciting for me is that we have just started to “scratch the surface” in this region.

So, despite a lasting low oil price environment we continue to stay firmly on track to deliver the next phase of the Company’s growth. This will be achieved by delivering Edvard Grieg field production safely, on schedule and on budget towards the end of the fourth quarter of this year, and having been offshore recently to review overall progress I am confident we will do just that.

The oil and gas industry

On the macro level, we continue to witness a volatile period characterised by fears of a global economic slowdown led by China and emerging markets in conjunction with a period of low oil prices led by an oversupply of oil mainly caused by US unconventional oil and increased OPEC production as producers battle to retain market share. At the same time we are assessing what impact additional production from Iran, Iraq and Libya may have on global supply of oil. On the other hand, we have reached a five year low for the onshore US rig count and a corresponding decline in unconventional oil production has commenced. Furthermore, on the conventional side, we see drastic budget reductions and project deferrals and cancellations impacting new development, appraisal and exploration activities which in time will significantly impact production growth and future global supply. In addition, we continue to see significant growth in world oil demand. So, a sustained low oil price environment will, as expected, negatively impact investment in all areas and eventually that will affect the global supply side. We already see clear evidence of that. I am optimistic that the oil price will eventually recover, however timing of such recovery remains questionable. As such, we have to be prepared for a potential sustained period of lower oil prices and, at the same time, take full advantage of the opportunities that this creates.

We are facing challenging times but our Company is indeed very well positioned as we are now entering a new phase of significant growth led by a great team of people. In my view Lundin Petroleum will come out of this cycle stronger than ever.

As Adolf Lundin used to tell us: “When the going gets tough, the tough get going”. This has never been more true than in today’s environment.

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 4 November 2015

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon three core areas: Norway, South East Asia and Continental Europe. Norway continues to represent the majority of Lundin Petroleum's operational activities with production for the nine month period ended 30 September 2015 (reporting period) accounting for 66 percent of total production and with 95 percent of Lundin Petroleum's total reserves.

Reserves and Resources

Lundin Petroleum has 702.5 million barrels of oil equivalents (MMboe) of reserves comprising 187.5 MMboe as at 31 December 2014 plus 515.0 MMboe of reserves from Johan Sverdrup effective as at 11 August 2015, all of which have been 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 404 MMboe as at 31 December 2014.

Production

Production for the reporting period amounted to 30.3 thousand barrels of oil equivalents per day (Mboepd) (compared to 24.4 Mboepd over the same period in 2014) and was comprised as follows:

Production in Mboepd	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Crude oil					
Norway	17.8	19.9	15.4	12.8	15.0
France	2.8	2.6	2.9	3.0	2.9
Malaysia	4.2	8.1	–	–	–
Total crude oil production	**24.8**	**30.6**	18.3	15.8	17.9
Gas					
Norway	2.1	2.0	2.7	2.3	2.6
Netherlands	1.7	1.9	1.9	1.8	1.9
Indonesia	1.7	1.5	1.5	1.5	1.4
Total gas production	**5.5**	**5.4**	6.1	5.6	5.9
Total production					
Quantity in Mboe	**8,263.7**	**3,312.3**	6,664.1	1,961.4	8,688.8
Quantity in Mboepd	**30.3**	**36.0**	24.4	21.4	23.8

Note: The comparatives have been restated following the sale of the Russian onshore assets in 2014.

Norway

Production

Production in Mboepd	WI [1]	**1 Jan 2015- 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014- 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014- 31 Dec 2014 12 months
Alvheim	15%	8.1	8.2	9.7	8.8	9.6
Volund	35%	5.2	4.8	7.8	5.9	7.4
Bøyla	15%	2.1	2.4	–	–	–
Brynhild	90%	4.2	6.2	–	–	0.1
Gaupe	40%	0.3	0.3	0.6	0.4	0.5
		19.9	**21.9**	18.1	15.1	17.6

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

Production from the Alvheim field during the reporting period has been substantially in line with forecast. Production levels during part of the first and second quarters of 2015 were somewhat restricted due to maintenance work on one of the gas compressors on the Alvheim FPSO as well as two wells being shut-in as a result of near-by infill drilling operations and well integrity issues respectively. The reservoir on the Alvheim field continues to perform well and the Alvheim FPSO also continues to achieve excellent uptime, in excess of 95 percent during the reporting period.

The drilling of two new infill wells on Alvheim has been successfully completed by the Transocean Winner rig during the reporting period. The first of these infill wells, the L4 well, commenced production in April 2015 and the second infill well, the K6 well, is expected to commence production in December 2015. During the reporting period the Transocean Winner rig also worked-over the Alvheim KB3 well which re-commenced production in May 2015. The Transocean Winner rig is currently drilling the A5 multi-lateral infill well with production expected to commence in mid-2016. The development of the Viper/Kobra discoveries was sanctioned by the Alvheim partnership in December 2014 with two production wells planned to be drilled in 2016 with an expected production start-up in late 2016. The cost of operations for the Alvheim field, excluding well intervention work, was below USD 5 per barrel during the reporting period.

The Volund field production during the reporting period was slightly below forecast due to liquid throughput and gas compression constraints on the Alvheim FPSO. Further infill opportunities have been identified on the Volund field and at least one further infill well is planned to be drilled. The cost of operations for the Volund field during the reporting period was below USD 4 per barrel.

The Bøyla field production during the reporting period has been in line with forecast. The Bøyla field commenced production in January 2015 from one production well with the water injection well coming on-line in March 2015. The third and final development well came onstream in August 2015 with subsequent plateau production being achieved.

Production from the Brynhild field during the reporting period has been ahead of forecast due to better than expected facilities uptime on the Haewene Brim FPSO. The initial production, which commenced in December 2014, was achieved from two production wells with the third and final production well having been put on production in late August 2015. The water injection system has been successfully tested and is expected to commence during the fourth quarter of 2015. Whilst production has been ahead of forecast, uptime performance remains a challenge with the re-occurrence of unplanned production shutdowns due to certain facilities related issues. In addition, earlier than expected water cut has led to a lower plateau production level compared to the originally guided gross production plateau of 12,000 bopd. Although there is only limited production data available and water injection is yet to commence, early indications from pressure data show that the development wells may be connected to lower volumes than originally estimated. A revised reserves estimate will be released early in 2016 following completion of the Company’s annual reserves audit process.

Despite no remaining reserves being attributed to the Gaupe field, the field recommenced production in April 2015 and will produce intermittently subject to favourable economic conditions.

Development

Licence	Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
PL338	Edvard Grieg	50%	Lundin Petroleum	June 2012	187 MMboe	Q4 2015	100.0 Mboepd
Various	Ivar Aasen	1.385%	Det norske	May 2013	192 MMboe	Q4 2016	65.0 Mboepd
Various	Johan Sverdrup	22.60%	Statoil	August 2015	1.65 - 3.02 billion boe	Late 2019	550.0 — 650.0 Mboepd

Edvard Grieg

The Edvard Grieg field is on schedule to achieve first oil towards the end of 2015. The commissioning and hook-up activities are progressing well with over 600 persons currently working on the Edvard Grieg installation. As of end October 2015, 80 percent of the commissioning and hook-up work had been completed.

A number of milestones have been achieved during the reporting period. In April 2015, Kværner completed the construction of the topsides on time and on budget. The offshore installation of the topsides on the pre-installed jacket was successfully completed during July 2015 by the Heerema heavy lift vessel Thialf. The new build flotel Safe Boreas which is being used for the offshore commissioning phase was bridge-linked to the Edvard Grieg platform in July 2015 and will remain on location until the offshore hook-up and commissioning activities have been completed. The Company has received consent from the Petroleum Safety Authority (PSA) to start production from the Edvard Grieg facilities upon completion of commissioning. The 94 km gas pipeline was installed in 2014 and the 43 km oil pipeline to the Grane oil export system was successfully installed during the reporting period. Development drilling commenced during the third quarter of 2014 with the Rowan Viking jack-up rig with the first two production wells successfully completed and ready for first oil. The Rowan Viking rig is currently being used for additional accommodation in relation to the hook-up and commissioning work and will re-commence the development drilling campaign in November 2015. A third production well will be ready around year end 2015. Plateau production from the Edvard Grieg field is expected during the second half of 2016 and development drilling will continue into 2018.

In August 2015 an appraisal well in the southern part of the Edvard Grieg field was successfully completed. The well encountered a 66 metres gross oil column of pebbly sandstone with medium to good reservoir quality. The results from the appraisal well are expected to result in a reserves increase for the Edvard Grieg field and the booking of such increased reserves is likely to occur at year end 2015.

Ivar Aasen

Ivar Aasen is being developed with a steel jacket platform with the topside facilities consisting of a living quarter and drilling facilities with oil, gas and water separation and onward export to the Edvard Grieg platform for final processing and pipeline export. The steel jacket was successfully installed in June 2015 and the pipeline installation commenced in the third quarter of 2015. The topside facilities are approximately 85 percent complete with mechanical completion expected in the first quarter of 2016. The topsides installation is scheduled during the summer of 2016. Ivar Aasen is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

The Johan Sverdrup project is progressing on schedule with a significant number of contracts now awarded and construction having commenced.

In February 2015, the Johan Sverdrup partnership submitted a Plan for Development and Operations (PDO) for Phase 1 to the Norwegian Ministry of Petroleum and Energy (MPE). The Norwegian Parliament endorsed the PDO in June 2015 and the MPE approved the PDO in August 2015. The PDO for Phase 1 also outlines certain concepts for the full field development involving an expected full field gross plateau production level of between 550,000 and 650,000 boepd and gross reserves of between 1.65 to 3.02 billion boe with approximately 95 percent of the reserves being oil.

In parallel with the PDO submission, the majority of the Johan Sverdrup partnership also submitted a unit operating agreement for the Johan Sverdrup field with a working interest of 22.12 percent to Lundin Petroleum. Due to the lack of agreement on the unitisation of the field it was left to the Minister of Petroleum and Energy to determine the partners' final working interest within the unitisation agreement. On 2 July 2015 the Minister of Petroleum and Energy announced the final working interest apportionment for the Johan Sverdrup field which resulted in Lundin Petroleum's working interest being increased to 22.60 percent from 22.12 percent.

The PDO for Phase 1 involves a field centre, consisting of one processing platform, one riser platform, one wellhead platform with drilling facilities and one living quarter platform. The platforms will be installed on steel jackets in 120 metres of water and will be bridge-linked. A significant number of contracts have already been awarded for the development of Phase 1. Notably all four topside contracts have been awarded, with EPC type contracts being awarded to Aibel (drilling platform) and Kværner /KBR (living quarters and utilities) whilst a fabrication contract has been awarded to Samsung Heavy Industries (riser platform and processing platform) with Aker Solutions being contracted for the procurement and engineering of the riser and processing platforms. The contract for the heavy lift installations for three of the topsides have been awarded to Allseas and contracts for the construction of three of the steel jackets for the riser, drilling and processing platforms have been awarded to Kværner whilst the contract for the jacket for the utility and living quarter platform has been awarded to Dragados Offshore. Odfjell Drilling has been awarded contracts for drilling of the wells. The pre-drilling template has been installed offshore with drilling scheduled to commence in the second quarter 2016.

The Phase 1 development is scheduled to start production in late 2019 and is forecast to have a gross production capacity of between 315,000 and 380,000 bopd. It is anticipated that 35 production and injection wells will be drilled to support Phase 1 production of which 14 wells will be drilled prior to first oil with a semi-submersible rig to facilitate Phase 1 plateau production.

At the time of submitting the Phase 1 PDO in February 2015 the capital expenditure for Phase 1 was estimated at gross NOK 117 billion (real 2015). With most of the material contracts now awarded the latest cost estimate has been reduced by approximately seven percent and with the continued deflationary environment within the supply chain, Lundin Petroleum believes that there is scope for further cost reductions.

Appraisal

2015 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL609	Lundin Petroleum	40%	7220/11-2 & 7220/11-2A	March 2015	Completed June 2015
PL609	Lundin Petroleum	40%	7220/11-3 & 7220/11-3 A	June 2015	Completed September 2015
PL338	Lundin Petroleum	50%	16/1-23S	June 2015	Completed August 2015

During the reporting period Lundin Petroleum has completed two Alta appraisal wells in the southern Barents Sea.

The Alta-2 appraisal well 7220/11-2 and sidetrack well 7220/11-2 A were drilled on the western part of the Alta discovery, approximately 6.5 km southwest of the discovery well 7220/11-1. The well 7220/11-2 encountered a 50 metres thick gas column in varying reservoir quality. The sidetrack well 7220/11-2 A was drilled a further 330 metres to the west and encountered moveable oil in improving reservoir quality and tested a maximum flow rate of 860 bopd and 0.65 million cubic feet of gas per day. Both the vertical well and the sidetrack proved pressure communication with the discovery well 6.5 km to the northeast.

The Alta-3 appraisal well 7220/11-3 and sidetrack well 7220/11-3 A were drilled on the eastern part of the Alta discovery, approximately four km south of the discovery well 7220/11-1 and three km northeast of the Alta-2 appraisal well. The well 7220/11-3 encountered a 120 metres thick hydrocarbon bearing interval, of which 45 metres in oil, in rocks of good to very good reservoir quality. The sidetrack well 7220/11-3 A, which was drilled 400 metres southeast of 7220/11-3, encountered a gross hydrocarbon column of 74 metres of which 44 metres was oil in reservoir rocks of varying quality. The well proved pressure communication with the discovery well and with Alta-2. Due to time constraints on the rig it was not possible to test the Alta-3 appraisal well.

In 2016 Lundin Petroleum is planning to re-enter the Alta-3 appraisal well to perform a production test as well as drilling two further appraisal wells.

Exploration

2015 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL338C	16/1-24	February	Gemini	50%	Lundin Petroleum	Dry
PL674BS	26/10-1	January	Zulu	35%	Lundin Petroleum	Gas discovery — non-commercial
PL359	16/4-9S	June	Luno II North	50%	Lundin Petroleum	Oil discovery
PL338C	16/1-25 S	October	Rolvsnes	50%	Lundin Petroleum	Ongoing
Southern Barents Sea						
PL708		Fourth quarter	Ørnen	40%	Lundin Petroleum	
PL609	7220/6-2	October	Neiden	40%	Lundin Petroleum	Ongoing
Other Areas						
PL579	33/2-1	March	Morkel	50%	Lundin Petroleum	Oil discovery — non-commercial
PL734	10/4-1	June	Zeppelin	30%	Wintershall	Dry
PL700		Fourth quarter	Lorry	40%	Lundin Petroleum	

Lundin Petroleum has completed five exploration wells in Norway during the reporting period.

The drilling of the Zulu prospect in PL674BS encountered a 24 metres sand sequence containing gas. The Zulu gas discovery is viewed as being non-commercial.

The drilling of the Gemini prospect in PL338C located immediately to the west of the Edvard Grieg field failed to encounter any hydrocarbons and the well was plugged and abandoned as dry.

The Zeppelin prospect in PL734 in the southern North Sea was announced as dry in July 2015. The well, which was operated by Wintershall, encountered a Vestland Group reservoir but was dry.

The Morkel prospect in PL579 in the northern North Sea was announced as a non-commercial oil discovery in June 2015. The well was drilled around 40 km northwest of the Snorre field and encountered Triassic sandstone over a 173 metre reservoir interval with low reservoir quality and poor production characteristics.

The drilling of the Luno II North prospect in PL359, 15 km south of Edvard Grieg was completed in August 2015 and resulted in an oil discovery. The well encountered a 23 metre gross oil column in Jurassic/Triassic conglomeratic sandstone of reasonable quality. A production test was carried out and achieved a flow rate of 1,000 bopd. The Luno II North discovery is estimated to contain between 12 and 26 MMboe of gross contingent resources.

Lundin Petroleum will drill another four wells offshore Norway during 2015 targeting net unrisked prospective resources of approximately 335 MMboe.

Lundin Petroleum is planning to drill at least three exploration wells in Norway in 2016. At least one well is planned to be drilled in the southern Barents Sea. Two exploration wells are planned to be drilled in the Utsira High area with one operated well in PL544 (WI 40%) targeting the Fosen prospect and one non-operated well in PL265 (WI 10%) targeting the Present prospect northwest of the Johan Sverdrup field. The 2016 exploration campaign in the Utsira High area is targeting net unrisked prospective resources of 80 MMboe.

Lundin Petroleum, together with 32 other companies signed a contract last year with Western Geco and PGS for an extended 3D seismic acquisition in the Norwegian east Barents Sea ahead of the 23rd licensing round. The 3D acquisition was completed in the third quarter of 2014 and the processing has been completed during the reporting period. In January 2015, the Norwegian Ministry of Petroleum and Energy announced that 57 blocks, or part blocks, will be offered for licensing in the 23rd Licensing round with the majority of blocks being located in the Barents Sea. The deadline for submitting licence applications is in December 2015, with awards expected to be announced during the first half of 2016. The Ministry of Petroleum and Energy has also announced the APA 2015 licensing round with an application deadline in September 2015 with possible awards expected during the first quarter of 2016.

Licence awards, transactions and relinquishments
In January 2015, the Ministry of Petroleum and Energy announced the licence awards in the 2014 APA licensing round. Lundin Petroleum was awarded eight licences of which six were awarded to Lundin Petroleum as operator.

During the reporting period, Lundin Petroleum farmed out 30 percent in PL338C (WI 50% after farm-out), 30 percent in PL544 (WI 40% after farm-out) and 30 percent in PL410 (WI 52.352% after farm-out) to Lime Petroleum Norway. During the reporting period licences PL490, PL641, PL646, PL639 and PL546 have been relinquished and Lundin Petroleum has withdrawn from PL583 and assumed operatorship of PL533 which is situated immediately to the west of the Alta discovery and on trend with the recent Castberg discovery in the southern Barents Sea. Lundin Petroleum also disposed of its interest in PL006C (WI 75%) which includes the South East Tor discovery to Faroe Petroleum. Certain of the above transactions and relinquishments remain subject to governmental approvals.

In October 2015, Lundin Petroleum completed the acquisition from EnQuest Norge AS of a 35 percent operated working interest in PL758 and PL800.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
France						
– Paris Basin	100%[1]	2.3	2.3	2.4	2.5	2.5
– Aquitaine	50%	0.5	0.3	0.5	0.5	0.4
Netherlands	Various	1.7	1.9	1.9	1.8	1.9
		4.5	**4.5**	4.8	4.8	4.8

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

France
Production levels during the reporting period from France have been substantially in line with forecast. Good production performance has been achieved from certain fields in the Aquitaine Basin following the completion of workover activities which has been offset by a slight underperformance from the Paris Basin production levels. As a precautionary measure one of the production flowlines on the Villeperdue field in the Paris Basin has been shut-in since August 2015 due to a failed pressure test. In September the majority of the production reliant upon the shut-in flowline was re-routed to a water injection flowline and thus most of the production has now resumed. In the Aquitaine Basin three fields have been shut-in since July 2015 due to a pipeline failure. An alternative transportation solution is expected to be implemented by year end 2015.

The construction of onshore facilities and the drilling and completion of two development wells on the Vert la Gravelle re-development project in the Paris Basin has been finalised and the wells have commenced production according to expectations.

The Netherlands
Production from the Netherlands has been ahead of forecast during the reporting period due to good production performance from the new Slootdorp 6 and 7 development wells.

The K5-A5 development well within the K4/K5 unit (WI 1.216%) was successfully drilled in 2014 and commenced production in May 2015. The E17-A5 (WI 1.20%) development well has been successfully drilled and completed during the reporting period and commenced production in July 2015. The Slootdorp-6 and 7 onshore development wells (WI 7.2325%) have both been completed and put into production in July 2015. The K5-A6 development well within the K4/K5 unit (WI 1.216%) was drilled during the reporting period, however the reservoir was found to be depleted and the well has been plugged and abandoned.

The Langezwaag-2 exploration well on the Gorredijk licence (WI 7.75%) was successfully drilled in 2014 and was put into production in January 2015.

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

South East Asia

Malaysia

Production

Production in Mboepd	WI	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Bertam	75%	**4.2**	**8.1**	–	–	–

Offshore, Peninsular Malaysia

Production levels from the Bertam field in PM307 (WI 75) during the reporting period have been substantially in line with forecast. The Bertam field achieved first oil in April 2015, commencing production from four pre-drilled wells. Since production start-up another seven wells have been completed and put onstream with the field producing from 11 wells as of mid-October 2015 with excellent uptime from the Bertam FPSO.

The development wells drilled to date on the Bertam field indicate that the western part of the field is structurally deeper than originally modelled whilst the eastern side of the field is structurally higher compared to the original model. The updated structural model has led to some changes in the development drilling sequence/targets of the later wells. In October 2015, the partnership drilled the successfull Bertam-3 appraisal well which confirmed additional resources in the northeastern part of the field. A long-reach horizontal development well will be drilled from the Bertam wellhead platform early in 2016 and put into production immediately after completion. With 11 wells now on production, the Bertam field achieved a gross peak production rate of approximately 14,000 boepd. The Bertam field is estimated to contain gross reserves of 18 MMboe and the total gross development costs are estimated at MUSD 400, excluding any FPSO related costs.

In October 2015 Lundin Petroleum completed the drilling of the Mengkuang exploration well 75 km northwest of the Bertam field in PM307. The well made a small gas discovery with 9 metres of high quality reservoir sands.

During the reporting period Lundin Petroleum has been assigned JX Nippon's equity of 40 percent in Block PM308A taking Lundin Petroleum's equity to 75 percent. Lundin Petroleum and Petronas Carigali have subsequently decided to drill the Selada prospect straddling Blocks PM307 (WI 75%) and PM308A (WI 75%) with the ownership in these two Blocks now fully aligned. The Selada exploration well will commence after the Bertam-3 appraisal well has been completed. The Selada prospect is approximately 15 km south of the Bertam field and in the event of an oil discovery the development solution would be as a tie-back to the Bertam FPSO.

Offshore Sabah, East Malaysia

Lundin Petroleum has completed the high-grading of its prospect inventory for SB307/SB308 (WI 85%) on existing 3D seismic and together with Petronas Carigali is planning to drill two exploration wells early in 2016. The two prospects being targeted, Imbok and Bambazon, are on trend with Shell's producing oil fields St Joseph, Barton and South Furious. The Imbok prospect is estimated to contain 53 MMboe and Bambazon 56 MMboe of gross unrisked prospective resources respectively. In July 2015, Lundin Petroleum assumed EnQuest's 42.5 percent working interest in SB307/SB308 increasing its working interest to 85 percent.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Singa	25.9%	**1.7**	**1.5**	1.5	1.5	1.4

The production from the Singa field has been substantially in line with forecast during the reporting period. The gas demand has been lower than normal during September and October 2015 due to excessive haze caused by forest fires in Indonesia which has negatively impacted production levels during these months.

In October 2015, Lundin Petroleum announced the signing of a sale and purchase agreement to sell its business in Indonesia to PT Medco Energi Internasional TBK for a cash consideration of MUSD 22 with an effective date of 1 October 2015. The Indonesian assets include the non-operated interest in the producing Singa gas field and the operated interests in the South Sokang and Cendrawasih VII Blocks, as well as the joint study agreement in respect of the Cendrawasih VIII Block. Lundin Petroleum may also become entitled to certain contingent payments in respect of the Singa gas field and retains an option to receive a future interest in the Cendrawasih Blocks. Completion of the transaction is subject to Indonesian governmental approval and is expected to occur during the first quarter of 2016.

Other Areas

Russia

Lagansky Block

In the Lagansky Block (WI 70%) in the northern Caspian a significant oil discovery, Morskaya, was made in 2008 and is estimated to contain gross best estimate 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 located within the Lagansky Block.

Corporate Responsibility

Sustainalytics ESG Report has ranked Lundin Petroleum above its peers and industry average from an environmental, social and governance perspective as of October 2015. It rated Lundin Petroleum as an “Outperformer” as the Company was ranked 17 out of 177 companies, placing Lundin Petroleum in the 91st percentile.

During the reporting period, Lundin Petroleum recorded two Lost Time Incidents (LTI). Its year to date LTI rate stands at 0.38 per 200,000 hours, while its total recordable incident rate (TRIR) is 0.91.

FINANCIAL REVIEW

Result

The net result for the nine month period ended 30 September 2015 (reporting period) amounted to MUSD -372.6 (MUSD 5.1). The loss was mainly due to lower oil prices and a higher financial expense as a result of the strong US dollar during the reporting period generating a largely non-cash foreign exchange charge, partly offset by a 24 percent increase in production. The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD -369.2 (MUSD 8.8) representing earnings per share of USD -1.19 (USD 0.03).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 291.1 (MUSD 506.9) representing EBITDA per share of USD 0.94 (USD 1.62). Operating cash flow for the reporting period amounted to MUSD 524.3 (MUSD 804.0) representing operating cash flow per share of USD 1.70 (USD 2.57).

Changes in the Group

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

Revenue

Revenue for the reporting period amounted to MUSD 433.3 (MUSD 650.0) 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 425.4 (MUSD 623.9). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 53.12 (USD 94.92) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 55.31 (USD 106.52) 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 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	4,939.9	2,101.7	4,001.8	790.9	5,183.3
– *Average price per boe*	*54.86*	*49.53*	*111.58*	*103.77*	*102.35*
France					
– Quantity in Mboe	768.4	217.2	804.9	351.9	1,028.7
– *Average price per boe*	*56.31*	*46.10*	*104.23*	*99.64*	*94.08*
Netherlands					
– Quantity in Mboe	1.2	0.6	1.1	0.5	1.1
– *Average price per boe*	*50.42*	*49.90*	*93.48*	*93.03*	*91.64*
Malaysia					
– Quantity in Mboe	842.8	620.1	–	–	–
– *Average price per boe*	*52.49*	*48.05*	–	–	–
Total crude oil sales					
– Quantity in Mboe	**6,552.3**	**2,939.6**	4,807.8	1,143.3	6,213.1
– Average price per boe	***54.73***	***48.96***	*110.34*	*102.49*	*100.98*
Gas and NGL sales					
Norway					
– Quantity in Mboe	569.7	177.9	865.0	226.7	1,080.8
– *Average price per boe*	*46.67*	*43.39*	*55.86*	*45.64*	*56.02*
Netherlands					
– Quantity in Mboe	473.9	170.1	526.5	163.9	687.9
– *Average price per boe*	*40.65*	*38.79*	*51.47*	*42.17*	*51.11*
Indonesia					
– Quantity in Mboe	412.7	130.1	373.8	130.2	457.2
– *Average price per boe*	*50.85*	*50.73*	*48.07*	*47.59*	*47.87*
Total gas and NGL sales					
– Quantity in Mboe	**1,456.3**	**478.1**	1,765.3	520.8	2,225.9
– *Average price per boe*	***45.90***	***43.75***	*52.90*	*45.03*	*52.83*
Total sales					
– Quantity in Mboe	**8,008.6**	**3,417.7**	6,573.1	1,664.1	8,439.0
– Average price per boe	***53.12***	***48.23***	*94.92*	*84.51*	*88.28*

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

The change in under/over lift position amounted to a net charge of MUSD 7.7 (credit of MUSD 13.8) in the reporting period. There was an overlift of entitlement movement on the Brynhild field partly offset by an underlift position from the fields in the Greater Alvheim Area during the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 15.6 (MUSD 12.3) for the reporting period and included third party 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 114.6 (MUSD 104.7) and are detailed in the table below.

Production costs	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Cost of operations					
– In MUSD	88.3	32.5	72.2	19.7	94.4
– In USD per boe	*10.68*	*9.80*	*10.84*	*10.06*	*10.86*
Tariff and transportation expenses					
– In MUSD	8.1	2.3	15.0	5.2	18.4
– In USD per boe	*0.99*	*0.70*	*2.25*	*2.65*	*2.12*
Royalty and direct production taxes					
– In MUSD	2.6	1.1	2.8	0.9	3.6
– In USD per boe	*0.31*	*0.33*	*0.42*	*0.47*	*0.41*
Change in inventory position					
– In MUSD	-5.8	-0.3	0.5	2.1	-0.8
– In USD per boe	*-0.70*	*-0.10*	*0.08*	*1.10*	*-0.09*
Other					
– In MUSD	21.4	14.5	14.2	-3.5	-49.1
– In USD per boe	*2.59*	*4.37*	*2.13*	*-1.82*	*-5.65*
Total production costs					
– In MUSD	**114.6**	**50.1**	104.7	24.4	66.5
– In USD per boe	***13.87***	***15.10***	*15.72*	*12.46*	*7.65*

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 88.3 (MUSD 72.2). The reporting period included costs of MUSD 7.3 associated with well intervention work on the Alvheim field and MUSD 5.0 on the Brynhild field mainly in relation to its share of the replacement cost of the mooring lines of the FPSO facilities. The total cost of operations excluding operational projects amounted to MUSD 73.5 (MUSD 52.9).The increase versus the comparative period is attributable to operating costs of the Brynhild and Bertam fields which came onstream in the fourth quarter of 2014 and the second quarter of 2015 respectively, partly offset by the impact of the stronger US Dollar on the funding of non-US Dollar denominated expenditures in the reporting period.

The cost of operations per barrel including operational projects amounted to USD 10.68 (USD 10.84) for the reporting period and excluding operational projects, the cost of operations amounted to USD 8.89 (USD 7.94) per barrel.

Tariff and transportation expenses for the reporting period amounted to MUSD 8.1 (MUSD 15.0). The decrease in costs compared to the same period last year is mainly due to lower volumes from the Volund and Gaupe fields in the reporting period.

Other costs amounted to MUSD 21.4 (MUSD 14.2) and 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 2014, an asset was recognised as at 31 December 2014. This asset is being charged to the income statement over the remaining term of the arrangement.

Depletion and decommissioning costs

Depletion costs associated with oil and gas properties amounted to MUSD 176.6 (MUSD 98.4) at an average rate of USD 21.38 (USD 14.76) per barrel and are detailed in Note 3. The higher depletion cost for the reporting period compared to the same period last year is due to the contributions of the Brynhild, Bøyla and Bertam fields, partly offset by lower production volumes on the Alvheim and Volund fields in the reporting period. Norway's contribution to the total depletion cost for the reporting period was 62 percent (66 percent) at an average rate of USD 20.16 (USD 13.19) per barrel.

Depletion cost of other assets amounted to MUSD 16.5 (MUSD -) for the reporting period and related to the Bertam FPSO.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 116.3 (MUSD 129.5) 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 third quarter of 2015, exploration costs relating to Norway of MUSD 9.4 were expensed and mainly related to the unsuccessful well that was drilled in PL734 (Zeppelin).

General, administrative and depreciation expenses
The general administrative and depreciation expenses for the reporting period amounted to MUSD 31.2 (MUSD 42.0) which included a charge of MUSD 5.9 (MUSD 8.5) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation charges for the reporting period amounted to MUSD 3.5 (MUSD 3.7).

Finance income
Finance income for the reporting period amounted to MUSD 1.7 (MUSD 1.3) and is detailed in Note 4.

Finance costs
Finance costs for the reporting period amounted to MUSD 455.2 (MUSD 113.0) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 47.0 (MUSD 11.7) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 31.4 (MUSD 26.9) associated with the funding of the Norwegian and Malaysian development projects was capitalised in the reporting period.

Net foreign exchange losses for the reporting period amounted to MUSD 378.1 (MUSD 66.8). 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 strengthened against the Euro during the reporting period resulting in a net foreign exchange loss on the US Dollar denominated external loan which is borrowed by a subsidiary using Euro as functional currency. In addition, the Norwegian Krone weakened against the Euro in the reporting period, generating a net foreign exchange loss on an intercompany loan balance denominated in Norwegian Krone. A strengthening US Dollar currency has a positive overall value effect on the business as it increases the purchasing power of the US Dollar to purchase the currencies in which the Group incurs operational expenditure. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar. For the reporting period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 108.5 (MUSD 5.5 gain).

The amortisation of the deferred financing fees amounted to MUSD 9.3 (MUSD 9.8) for the reporting period and related to the expensing of the fees incurred in establishing the financing facilities, including the Norwegian exploration financing facility, over the period of usage of the facilities.

Loan facility commitment fees for the reporting period amounted to MUSD 6.7 (MUSD 16.9) with the decrease compared to the same period last year being due to the increased borrowings under the financing arrangements.

Tax
The tax credit for the reporting period amounted to MUSD 102.8 (charge of MUSD 145.7).

The current tax credit for the reporting period amounted to MUSD 205.5 (MUSD 258.7) which included MUSD 208.9 (MUSD 274.4) relating to the Norway exploration tax refund due to the significant level of development and exploration and appraisal expenditure in Norway in the reporting period and the tax depreciation on development expenditure incurred in prior years. The current tax credit in Norway for the reporting period is partly offset by the current tax charge relating to operations in France and the Netherlands.

The deferred tax charge for the reporting period amounted to MUSD 102.7 (MUSD 404.4) which predominantly related to Norway. The deferred tax charge arises primarily where there is a difference in depletion for tax and accounting purposes.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 percent and 78 percent. The effective tax rate for the reporting period is affected by items which do not receive a full tax credit such as the net foreign exchange loss reported and by the uplift allowance applicable in Norway for development expenditures against the offshore 51 percent tax regime.

Non-controlling interest
The net result attributable to non-controlling interest for the reporting period amounted to MUSD -3.4 (MUSD -3.7) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,623.6 (MUSD 4,182.6) 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 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Norway	661.7	180.1	818.7	243.5	1,068.2
France	15.9	1.5	14.6	8.4	29.3
Netherlands	2.0	0.3	2.8	0.8	3.9
Indonesia	-0.6	0.1	-0.6	-0.6	-0.8
Malaysia	134.7	30.2	97.8	48.9	130.6
	813.7	**212.2**	933.3	301.0	1,231.2

An amount of MUSD 661.7 (MUSD 818.7) of development expenditure was incurred in Norway during the reporting period, primarily on the Edvard Grieg, Brynhild, Ivar Aasen, and Johan Sverdrup field developments. In Malaysia, MUSD 134.7 (MUSD 97.8) was incurred during the reporting period on the Bertam field development.

An amount of MUSD 31.3 (MUSD 102.5) was incurred during the reporting period on the Bertam FPSO facilities. This amount is not shown in the table above and has been capitalised as part of other tangible fixed assets.

Exploration and appraisal expenditure in MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Norway	268.7	99.7	351.5	140.5	572.8
France	0.4	–	2.2	0.5	5.9
Indonesia	3.1	0.4	30.0	2.4	47.5
Malaysia	7.5	2.9	30.0	18.6	42.7
Russia	4.1	0.5	2.6	0.7	4.0
Other	1.4	0.2	1.4	0.5	1.6
	285.2	**103.7**	417.7	163.2	674.5

Exploration and appraisal expenditure of MUSD 268.7 (MUSD 351.5) was incurred in Norway during the reporting period, primarily on the appraisal drilling of the Alta discovery in the southern Barents Sea and the Edvard Grieg southeast appraisal well, and on the drilling of five exploration wells.

Other tangible fixed assets amounted to MUSD 212.6 (MUSD 200.3) and included expenditures relating to the Bertam FPSO.

Financial assets amounted to MUSD 16.5 (MUSD 37.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 5.4 (MUSD 4.7) 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. The main change in the value since the year end relates to the additional shares acquired from the ShaMaran rights issue completed during the first quarter of 2015, see also Related Party Transactions section below. Brynhild operating cost share amounted to MUSD 9.5 (MUSD 31.0) and related to the long-term portion of the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price.

Deferred tax assets amounted to MUSD 14.4 (MUSD 12.9) and are mainly related to the part of the tax loss carry forwards in the Netherlands that are expected to be utilised against future tax liabilities.

Other non-current assets amounted to MUSD 196.7 (MUSD –) and related to the Norwegian corporate tax refund in respect of the current year which will be received in December 2016.

Current assets
Inventories amounted to MUSD 38.2 (MUSD 41.6) and included both well supplies mainly held in Norway and Malaysia and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 191.0 (MUSD 163.5) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 79.1 (MUSD 40.3). Underlift amounted to MUSD 9.9 (MUSD 3.6) and was mainly attributable to a net underlift position in Norway from the fields in the Greater Alvheim Area. Joint operations debtors amounted to MUSD 38.2 (MUSD 49.1) and the comparative amount included an amount that was settled in January 2015. Prepaid expenses and accrued income amounted to MUSD 32.9 (MUSD 41.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 16.2 (MUSD 21.6) and related to the short-term portion of the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price. Other current assets amounted to MUSD 14.7 (MUSD 7.4) and included a receivable on Johan Sverdrup past costs following the assigned equity in the unit, VAT and other miscellaneous balances.

Current tax assets amounted to MUSD 323.7 (MUSD 373.6) and mainly related to the Norwegian corporate tax refund in respect of 2014 which is due to be received in December 2015. The amount is denominated in Norwegian Kroner and the movement in US Dollar terms since year end results from the strengthening of the US Dollar against the Norwegian Krone.

Cash and cash equivalents amounted to MUSD 53.0 (MUSD 80.5). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities
Financial liabilities amounted to MUSD 3,736.8 (MUSD 2,654.0) and are detailed in Note 11. Bank loans amounted to MUSD 3,763.0 (MUSD 2,690.0) and related to the outstanding loan under the Group's USD 4.0 billion revolving borrowing base facility. Capitalised financing fees relating to the establishment costs of the financing facilities, including the Norwegian exploration financing facility, amounted to MUSD 26.2 (MUSD 36.0) and are being amortised over the expected life of the financing facilities.

Provisions amounted to MUSD 315.2 (MUSD 288.0) and are detailed in Note 12. The provision for site restoration amounted to MUSD 304.6 (MUSD 274.1) and related to future decommissioning obligations. The provision has increased during the reporting period due to additions relating to the Norwegian and Malaysian development projects. Farm-in payment amounted to MUSD 4.6 (MUSD 7.5) and related to a provision for payments towards historic costs based on production milestones on Block PM307, Malaysia.

Deferred tax liabilities amounted to MUSD 965.4 (MUSD 973.3) of which MUSD 832.5 (MUSD 844.8) related to Norway. The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

Derivative instruments amounted to MUSD 46.2 (MUSD 33.9) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedges due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 31.5 (MUSD 29.1) and mainly represent the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities
Trade and other payables amounted to MUSD 327.1 (MUSD 491.4) and are detailed in Note 13. Joint operations creditors and accrued expenses amounted to MUSD 256.4 (MUSD 383.5) and related mainly to the development and drilling activity in Norway and on the Bertam field, Malaysia. Other accrued expenses amounted to MUSD 32.1 (MUSD 46.1) and included an amount of MUSD 6.9 (MUSD 19.4) relating to the work remaining to be done on the Bertam FPSO. The liability for the long-term incentive plans amounted to MUSD - (MUSD 28.2) following the payment of the outstanding amounts under the 2009 phantom option plan.

Financial liabilities amounted to MUSD 134.4 (MUSD -) and represented the amount that had been drawn under the Norwegian exploration financing facility.

Derivative instruments amounted to MUSD 77.3 (MUSD 101.4) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 3.4 (MUSD 53.4). Included in the comparative period was MUSD 48.5 relating to a payment for historic costs on Block PM307, Malaysia, payable on first oil from the Bertam field. Following first oil from the Bertam field in April 2015, the liability was settled during the reporting period. The liability was in Malaysian Ringgit and due to the strengthening of the US Dollar against the Malaysian Ringgit and a reduction in the agreed historic costs, the amount paid was MUSD 34.8 in US Dollar terms. An amount of MUSD 3.4 (MUSD 4.9) relating to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan is included in current provisions.

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 -55.9 (MSEK -101.1) for the reporting period.

The result included general and administrative expenses of MSEK 67.9 (MSEK 109.8) and finance income of MSEK 3.7 (MSEK 3.0).

Pledged assets of MSEK 5,670.6 (MSEK 8,717.8) 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 year, the Group has entered into transactions with related parties on a commercial basis as described below.

The Group received MUSD 0.3 (MUSD 0.2) from related parties for the provision of office and other services. The Group paid MUSD — (MUSD 0.1) to related parties in respect of services received.

Following a rights issue by ShaMaran Petroleum that was completed in February 2015, Lundin Petroleum acquired 46.5 million ShaMaran shares for a total consideration of CAD 4.65 million and received a further 7.3 million ShaMaran shares as a fee for guaranteeing the offering along with other major shareholders. As at 30 September 2015, Lundin Petroleum holds a total of 103.8 million ShaMaran shares, representing approximately 6.6 percent of the total outstanding ShaMaran shares at that date.

Liquidity
In 2014, Lundin Petroleum increased its financing facility to USD 4.0 billion. The financing facility is a revolving borrowing base facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields and fields under development at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 30 September 2015 is MUSD 675.2 (MUSD 1,126.8) equivalent and represents the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above. The Group is not in breach of its financing facility agreement.

In April 2015, Lundin Petroleum entered into a NOK 4.5 billion Norwegian exploration financing 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.

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 2015 was MUSD 30.1. An additional bank guarantee in support of work commitments in Indonesia was also in place at 30 September 2015 for an amount of MUSD 1.0.

Subsequent Events
In October 2015, Lundin Petroleum announced the signing of a sale and purchase agreement to sell its business in Indonesia to PT Medco Energi Internasional TBK. Completion of the transaction is subject to Indonesian governmental approval and is expected to occur during the first quarter of 2016.

In October 2015, Lundin Petroleum announced that the Mengkuang-1 exploration well in Block PM307, offshore Malaysia, was a small gas discovery. The cost of the well will be expensed in the fourth quarter of 2015.

Share Data
Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 311,070,330 shares with a quota value of SEK 0.01 each. At 30 September 2015 the Company holds 2,000,000 of its own shares.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2014 Annual Report and in the materials provided to shareholders in respect of the 2015 AGM, available on www.lundin-petroleum.com.

Unit Bonus Plan

The number of units relating to the awards made in 2013, 2014 and 2015 under the Unit Bonus Plan outstanding as at 30 September 2015 were 133,922, 250,016 and 441,831 respectively.

Performance Based Incentive Plan

The AGM 2015 resolved a long-term performance based incentive plan in respect of Group management and a number of key employees. The plan is effective from 1 July 2015 and the 2015 award has been accounted for from the second half of 2015. The total awards made in respect of 2015 were 705,406 and vest over three years subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 91.40 using an option pricing model.

The 2014 plan is effective from 1 July 2014 and the total number of awards made in respect of 2014 was 608,103 and the related cost is recognised on a straight line basis over the three year performance period. Each award was fair valued at the date of grant at SEK 81.40 using an option pricing model.

Accounting Policies

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

The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2014.

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 2014 Annual Report.

Derivative financial instruments

In September 2015, Lundin Petroleum entered into new forward currency hedges to meet part of its future NOK capital requirements relating to the Johan Sverdrup field development. At 30 September 2015, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 632.4	MUSD 99.1	NOK 6.38:USD 1	Oct 2015 – Dec 2015
MNOK 1,251.8	MUSD 182.5	NOK 6.86:USD 1	Jan 2016 – Jun 2016
MNOK 2,058.4*	MUSD 243.9	NOK 8.44:USD 1	Jul 2016 – Dec 2016
MNOK 1,839.2*	MUSD 217.3	NOK 8.46:USD 1	Jan 2017 – Dec 2017
MNOK 1,928.0*	MUSD 228.0	NOK 8.46:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4*	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

* New hedging contracts entered into during September 2015 (summarised by year)

At 30 September 2015, 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
500	0.57%	1 Apr 2013 – 31 Mar 2016
1,500	0.52%	1 Jan 2015 – 31 Dec 2015
1,500	1.50%	1 Jan 2016 – 31 Mar 2016
2,000	1.50%	1 Apr 2016 – 31 Dec 2016
1,500	2.32%	1 Jan 2017 – 31 Dec 2017
1,000	3.06%	1 Jan 2018 – 31 Dec 2018

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

Exchange Rates

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

	30 Sep 2015		30 Sep 2014		31 Dec 2014	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	7.9077	8.5017	6.1081	6.4524	6.3011	7.4332
1 USD equals Euro	0.8973	0.8926	0.7378	0.7947	0.7526	0.8236
1 USD equals Rouble	57.7152	65.3768	35.4430	35.5496	38.3878	59.5808
1 USD equals SEK	8.4089	8.3980	6.6680	7.2689	6.8457	7.7366

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Revenue	1	**433.3**	**154.2**	650.0	189.2	785.2
Cost of sales						
Production costs	2	-114.6	-50.1	-104.7	-24.4	-66.5
Depletion and decommissioning costs		-176.6	-78.1	-98.4	-29.6	-131.6
Depletion of other assets		-16.5	-8.3	–	–	–
Exploration costs		-116.3	-9.4	-129.5	-0.3	-386.4
Impairment costs of oil and gas properties		–	–	–	–	-400.7
Gross profit	3	**9.3**	**8.3**	317.4	134.9	-200.0
General, administration and depreciation expenses		-31.2	-6.8	-42.0	-8.3	-52.2
Operating profit		**-21.9**	**1.5**	275.4	126.6	-252.2
Result from financial investments						
Finance income	4	1.7	0.4	1.3	0.3	1.8
Finance costs	5	-455.2	-230.2	-113.0	-74.5	-421.8
		-453.5	**-229.8**	-111.7	-74.2	-420.0
Share of the result of joint ventures accounted for using the equity method		–	–	-12.9	–	-12.9
Profit before tax		**-475.4**	**-228.3**	150.8	52.4	-685.1
Income tax	6	102.8	26.7	-145.7	-48.1	253.2
Net result		**-372.6**	**-201.6**	5.1	4.3	-431.9
Attributable to:						
Owners of the Parent Company		-369.2	-200.4	8.8	5.6	-427.2
Non-controlling interest		-3.4	-1.2	-3.7	-1.3	-4.7
		-372.6	**-201.6**	5.1	4.3	-431.9
Earnings per share – USD[1]		-1.19	-0.65	0.03	0.02	-1.38
Earnings per share fully diluted – USD[1]		-1.19	-0.65	0.03	0.02	-1.38

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Net result	**-372.6**	**-201.6**	5.1	4.3	-431.9
Other comprehensive income					
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-67.0	-49.4	-101.1	-84.8	-196.3
Cash flow hedges	1.3	-17.2	-37.1	-27.0	-148.7
Available-for-sale financial assets	-2.8	-2.2	-6.3	-4.3	-15.3
Other comprehensive income, net of tax	-68.5	-68.8	-144.5	-116.1	-360.3
Total comprehensive income	**-441.1**	**-270.4**	-139.4	-111.8	-792.2
Attributable to:					
Owners of the Parent Company	-435.2	-265.0	-127.9	-104.4	-766.7
Non-controlling interest	-5.9	-5.4	-11.5	-7.4	-25.5
	-441.1	**-270.4**	-139.4	-111.8	-792.2

Consolidated Balance Sheet

Expressed in MUSD	Note	30 September 2015	31 December 2014
ASSETS			
Non-current assets			
Oil and gas properties	7	4,623.6	4,182.6
Other tangible fixed assets		212.6	200.3
Financial assets	8	16.5	37.0
Deferred tax assets		14.4	12.9
Other non-current assets	9	196.7	–
Total non-current assets		**5,063.8**	4,432.8
Current assets			
Inventories		38.2	41.6
Trade and other receivables	10	191.0	163.5
Current tax assets		323.7	373.6
Cash and cash equivalents		53.0	80.5
Total current assets		**605.9**	659.2
TOTAL ASSETS		**5,669.7**	5,092.0
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		0.9	431.5
Non-controlling interest		28.2	34.2
Total equity		**29.1**	465.7
Liabilities			
Non-current liabilities			
Financial liabilities	11	3,736.8	2,654.0
Provisions	12	315.2	288.0
Deferred tax liabilities		965.4	973.3
Derivative instruments	14	46.2	33.9
Other non-current liabilities		31.5	29.1
Total non-current liabilities		**5,095.1**	3,978.3
Current liabilities			
Trade and other payables	13	327.1	491.4
Financial liabilities	11	134.4	–
Derivative instruments	14	77.3	101.4
Current tax liabilities		3.3	1.8
Provisions	12	3.4	53.4
Total current liabilities		**545.5**	648.0
Total liabilities		**5,640.6**	4,626.3
TOTAL EQUITY AND LIABILITIES		**5,669.7**	5,092.0

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Cash flows from operating activities					
Net result	-372.6	-201.6	5.1	4.3	-431.9
Adjustments for:					
Exploration costs	116.3	9.4	129.5	0.3	386.4
Depletion, depreciation and amortisation	196.7	87.8	102.1	30.8	136.2
Current tax	-205.5	-72.7	-258.7	-142.2	-419.7
Deferred tax	102.7	46.0	404.4	190.3	166.5
Impairment of oil and gas properties	–	–	–	–	400.7
Long-term incentive plans	11.6	1.8	12.5	1.6	14.5
Foreign currency exchange loss	269.6	172.6	71.8	38.8	333.1
Interest expense	47.0	19.2	11.7	4.9	21.1
Other	34.4	15.1	27.1	21.6	-5.1
Interest received	0.4	0.1	0.5	0.2	0.9
Interest paid	-77.3	-30.5	-37.7	-14.9	-56.5
Income taxes paid	0.2	0.1	-12.3	-3.7	-13.8
Changes in working capital	-81.1	24.1	132.5	56.9	72.4
Total cash flows from operating activities	**42.4**	**71.4**	588.5	187.9	604.8
Cash flows from investing activities					
Investment in oil and gas properties	-1,098.9	-315.9	-1,351.0	-464.2	-1,921.2
Investment in other fixed assets	-34.5	-2.1	-105.9	-25.5	-124.9
Disposal of bonds	–	–	10.5	–	10.5
Investment in subsidiaries	-0.1	-0.1	–	–	–
Investment in other shares and participations	-3.7	–	–	–	–
Share in result in associated company	–	–	11.7	11.7	11.7
Decommissioning costs paid	-9.6	-5.5	-0.9	-0.5	-1.2
Other payments	-0.5	–	-0.1	–	-0.1
Total cash flows from investing activities	**-1,147.3**	**-323.6**	-1,435.7	-478.5	-2,025.2
Cash flows from financing activities					
Changes in long-term receivables	–	–	9.8	9.9	9.8
Changes in long-term liabilities	1,075.4	210.6	892.9	316.7	1,419.2
Financing fees paid	-3.2	-0.1	-20.7	–	-20.7
Purchase of own shares	–	–	-9.8	–	-9.8
Distributions	–	–	-0.1	–	-0.1
Total cash flows from financing activities	**1,072.2**	**210.5**	872.1	326.6	1,398.4
Change in cash and cash equivalents	-32.7	-41.7	24.9	37.0	-22.0
Cash and cash equivalents at the beginning of the period	80.5	93.0	82.4	73.1	82.4
Currency exchange difference in cash and cash equivalents	5.2	1.7	4.6	1.8	20.1
Cash and cash equivalents at the end of the period	**53.0**	**53.0**	111.9	111.9	80.5

Consolidated Statement of Changes in Equity

	Attributable to owners of the Parent Company					
Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
At 1 January 2014	**0.5**	**358.1**	**848.4**	**1,207.0**	**59.8**	**1,266.8**
Comprehensive income						
Net result	–	–	8.8	8.8	-3.7	5.1
Other comprehensive income	–	-136.7	–	-136.7	-7.8	-144.5
Total comprehensive income	**–**	**-136.7**	**8.8**	**-127.9**	**-11.5**	**-139.4**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Value of employee services	–	–	0.6	0.6	–	0.6
Total transactions with owners	**–**	**-9.8**	**0.6**	**-9.2**	**-0.1**	**-9.3**
At 30 September 2014	**0.5**	**211.6**	**857.8**	**1,069.9**	**48.2**	**1,118.1**
Comprehensive income						
Net result	–		-436.0	-436.0	-1.0	-437.0
Other comprehensive income	–	-202.8		-202.8	-13.0	-215.8
Total comprehensive income	**–**	**-202.8**	**-436.0**	**-638.8**	**-14.0**	**-652.8**
Transactions with owners						
Value of employee services	–	–	0.4	0.4	–	0.4
Total transaction with owners	**–**	**–**	**0.4**	**0.4**	**–**	**0.4**
At 31 December 2014	**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 transaction 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**

In 2014 the Parent Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount. The amounts were recognised against other reserves. In consequence the cancellation of shares did not impact the Company's share capital.

Notes to the Consolidated Financial Statements

Note 1. Revenue MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Crude oil	358.6	143.9	530.5	117.2	627.4
Condensate	0.4	0.1	2.8	1.0	3.0
Gas	66.4	20.8	90.6	22.4	114.6
Net sales of oil and gas	**425.4**	**164.8**	623.9	140.6	745.0
Change in under/over lift position	-7.7	-17.4	13.8	44.3	23.4
Other revenue	15.6	6.8	12.3	4.3	16.8
Revenue	**433.3**	**154.2**	650.0	189.2	785.2

Note 2. Production costs MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Cost of operations	88.3	32.5	72.2	19.7	94.4
Tariff and transportation expenses	8.1	2.3	15.0	5.2	18.4
Direct production taxes	2.6	1.1	2.8	0.9	3.6
Change in inventory position	-5.8	-0.3	0.5	2.1	-0.8
Other	21.4	14.5	14.2	-3.5	-49.1
	114.6	**50.1**	104.7	24.4	66.5

Note 3. Segment information MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Norway					
Crude oil	271.0	104.1	446.5	82.1	530.5
Condensate	–	–	1.7	0.6	1.7
Gas	26.6	7.7	46.6	9.7	58.8
Net sales of oil and gas	**297.6**	**111.8**	494.8	92.4	591.0
Change in under/over lift position	-7.7	-17.2	14.4	44.8	24.4
Other revenue	1.6	0.5	3.1	0.8	3.8
Revenue	**291.5**	**95.1**	512.3	138.0	619.2
Production costs	-81.1	-36.4	-63.9	-8.1	-11.3
Depletion and decommissioning costs	-109.3	-44.0	-64.9	-18.5	-88.5
Exploration costs	-115.3	-9.4	-74.2	0.4	-272.1
Impairment costs of oil and gas properties	–	–	–	–	-400.7
Gross profit	**-14.2**	**5.3**	309.3	111.8	-153.4

Note 3. Segment information cont. MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
France					
Crude oil	43.3	10.0	83.9	35.1	96.8
Net sales of oil and gas	**43.3**	**10.0**	83.9	35.1	96.8
Change in under/over lift position	–	-0.2	0.1	-0.2	-0.5
Other revenue	1.1	0.4	1.3	0.4	1.7
Revenue	**44.4**	**10.2**	85.3	35.3	98.0
Production costs	-18.8	-5.2	-25.2	-10.4	-33.1
Depletion and decommissioning costs	-12.0	-3.7	-12.8	-4.2	-16.9
Exploration costs	-0.6	–	–	–	-4.6
Gross profit	**13.0**	**1.3**	47.3	20.7	43.4
Netherlands					
Crude oil	0.1	0.1	0.1	–	0.1
Condensate	0.4	0.1	1.1	0.4	1.3
Gas	18.8	6.5	26.0	6.5	33.8
Net sales of oil and gas	**19.3**	**6.7**	27.2	6.9	35.2
Change in under/over lift position	–	–	-0.7	-0.3	-0.5
Other revenue	1.3	0.4	1.7	0.7	2.2
Revenue	**20.6**	**7.1**	28.2	7.3	36.9
Production costs	-9.0	-3.2	-12.1	-4.5	-16.8
Depletion and decommissioning costs	-8.2	-2.7	-12.2	-3.9	-15.9
Exploration costs	-0.4	–	-1.0	-0.5	-1.4
Gross profit	**3.0**	**1.2**	2.9	-1.6	2.8
Malaysia					
Crude oil	44.2	29.7	–	–	–
Net sales of oil and gas	**44.2**	**29.7**	–	–	–
Other revenue	7.0	3.5	–	–	–
Revenue	**51.2**	**33.2**	–	–	–
Production costs	-3.1	-4.7	–	–	–
Depletion and decommissioning costs	-38.0	-24.8	–	–	–
Depletion of other assets	-16.5	-8.3	–	–	
Exploration costs	–	–	–	–	-14.4
Gross profit	**-6.4**	**-4.6**	–	–	-14.4
Indonesia					
Gas	21.0	6.6	18.0	6.2	22.0
Net sales of oil and gas	**21.0**	**6.6**	18.0	6.2	22.0
Other revenue	–	–	–	–	–
Revenue	**21.0**	**6.6**	18.0	6.2	22.0
Production costs	-2.6	-0.6	-3.5	-1.4	-5.4
Depletion and decommissioning costs	-9.1	-2.9	-8.5	-3.0	-10.3
Exploration costs	–	–	-54.2	-0.2	-94.2
Gross profit	**9.3**	**3.1**	-48.2	1.6	-87.9

Note 3. Segment information cont. MUSD	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Other					
Crude oil	–	–	–	–	–
Net sales of oil and gas	–	–	–	–	–
Other revenue	4.6	2.0	6.2	2.4	9.1
Revenue	**4.6**	**2.0**	6.2	2.4	9.1
Production costs	–	–	–	–	0.1
Depletion and decommissioning costs	–	–	–	–	–
Exploration costs	–	–	-0.1	–	0.3
Gross profit	**4.6**	**2.0**	6.1	2.4	9.5

Total					
Crude oil	358.6	143.9	530.5	117.2	627.4
Condensate	0.4	0.1	2.8	1.0	3.0
Gas	66.4	20.8	90.6	22.4	114.6
Net sales of oil and gas	**425.4**	**164.8**	623.9	140.6	745.0
Change in under/over lift position	-7.7	-17.4	13.8	44.3	23.4
Other revenue	15.6	6.8	12.3	4.3	16.8
Revenue	**433.3**	**154.2**	650.0	189.2	785.2
Production costs	-114.6	-50.1	-104.7	-24.4	-66.5
Depletion and decommissioning costs	-176.6	-78.1	-98.4	-29.6	-131.6
Depletion of other assets	-16.5	-8.3	–	–	–
Exploration costs	-116.3	-9.4	-129.5	-0.3	-386.4
Impairment costs of oil and gas properties	–	–	–	–	-400.7
Gross profit	**9.3**	**8.3**	317.4	134.9	-200.0

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 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Interest income	0.5	0.2	0.8	0.2	1.2
Foreign currency exchange gain, net	–	–	–	–	–
Guarantee fees	0.7	–	0.4	0.1	0.5
Other	0.5	0.2	0.1	–	0.1
	1.7	**0.4**	1.3	0.3	1.8

Note 5. Finance costs MUSD	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Interest expense	47.0	19.2	11.7	4.9	21.1
Foreign currency exchange loss, net	378.1	201.4	66.8	58.0	356.3
Result on interest rate hedge settlement	5.3	1.8	1.7	0.7	2.4
Unwinding of site restoration discount	7.5	2.7	5.3	1.7	7.0
Amortisation of deferred financing fees	9.3	3.2	9.8	3.7	12.6
Loan facility commitment fees	6.7	1.5	16.9	5.5	21.4
Other	1.3	0.4	0.8	–	1.0
	455.2	**230.2**	113.0	74.5	421.8

Note 6. Income tax MUSD	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014– 30 Sep 2014 9 months	1 Jul 2014– 30 Sep 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Current tax	-205.5	-72.7	-258.7	-142.2	-419.7
Deferred tax	102.7	46.0	404.4	190.3	166.5
	-102.8	**-26.7**	145.7	48.1	-253.2

Note 7. Oil and gas properties MUSD	**30 Sep 2015**	31 Dec 2014
Norway	3,318.2	2,960.7
France	198.5	210.1
Netherlands	30.4	38.6
Malaysia	541.4	428.3
Indonesia	37.3	43.9
Russia	497.8	501.0
	4,623.6	4,182.6

Note 8. Financial assets MUSD	**30 Sep 2015**	31 Dec 2014
Other shares and participations	5.4	4.7
Brynhild operating cost share	9.5	31.0
Other	1.6	1.3
	16.5	37.0

Note 9. Other non-current assets MUSD	**30 Sep 2015**	31 Dec 2014
Corporate tax	196.7	–
	196.7	–

Note 10. Trade and other receivables MUSD	**30 Sep 2015**	31 Dec 2014
Trade receivables	79.1	40.3
Underlift	9.9	3.6
Joint operations debtors	38.2	49.1
Prepaid expenses and accrued income	32.9	41.5
Brynhild operating cost share	16.2	21.6
Other	14.7	7.4
	191.0	163.5

Note 11. Financial liabilities

MUSD	**30 Sep 2015**	31 Dec 2014
Non-current:		
Bank loans	3,763.0	2,690.0
Capitalised financing fees	-26.2	-36.0
	3,736.8	2,654.0
Current:		
Short-term bank loans	134.4	–
	134.4	–
	3,871.2	2,654.0

Note 12. Provisions

MUSD	**30 Sep 2015**	31 Dec 2014
Non-current:		
Site restoration	304.6	274.1
Long-term incentive plans	1.4	1.8
Farm-in payment	4.6	7.5
Other	4.6	4.6
	315.2	288.0
Current:		
Farm-in payment	–	48.5
Long-term incentive plans	3.4	4.9
	3.4	53.4
	318.6	341.4

Note 13. Trade and other payables

MUSD	**30 Sep 2015**	31 Dec 2014
Trade payables	19.2	23.9
Overlift	13.7	–
Joint operations creditors and accrued expenses	256.4	383.5
Other accrued expenses	32.1	46.1
Long-term incentive plans	–	28.2
Other	5.7	9.7
	327.1	491.4

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 2015

MUSD	Level 1	Level 2	Level 3
Assets			
Cash and cash equivalents	53.0	–	–
Financial assets	16.5	–	–
	69.5	**–**	**–**
Liabilities			
Derivative instruments – non-current	–	46.2	–
Derivative instruments – current	–	77.3	–
	–	**123.5**	**–**

31 December 2014

MUSD	Level 1	Level 2	Level 3
Assets			
Cash and cash equivalents	80.5	–	–
Financial assets	37.0	–	–
	117.5	**–**	**–**
Liabilities			
Derivative instruments – non-current	–	33.9	–
Derivative instruments – current	–	101.4	–
	–	**135.3**	**–**

There were no transfers between the levels during the year.

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 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Revenue	**8.4**	**0.9**	7.6	1.0	9.2
General and administration expenses	-67.9	-17.3	-109.8	-25.3	-144.9
Operating profit	**-59.5**	**-16.4**	-102.2	-24.3	-135.7
Result from financial investments					
Finance income	3.7	1.2	3.0	1.2	209.9
Finance costs	-0.1	-0.1	-1.9	- 0.1	-1.9
	3.6	**1.1**	1.1	1.1	208.0
Profit before tax	**-55.9**	**-15.3**	-101.1	-23.2	72.3
Income tax	–	–	–	–	36.4
Net result	**-55.9**	**-15.3**	-101.1	-23.2	108.7

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Net result	**-55.9**	**-15.3**	-101.1	-23.2	108.7
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**-55.9**	**-15.3**	-101.1	-23.2	108.7
Attributable to:					
Shareholders of the Parent Company	-55.9	-15.3	-101.1	-23.2	108.7
	-55.9	**-15.3**	-101.1	-23.2	108.7

Parent Company Balance Sheet

Expressed in MSEK	**30 September 2015**	31 December 2014
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Other tangible fixed assets	0.2	0.2
Total non-current assets	**7,872.0**	7,872.0
Current assets		
Receivables	16.7	16.7
Cash and cash equivalents	1.9	1.8
Total current assets	**18.6**	18.5
TOTAL ASSETS	**7,890.6**	7,890.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,804.6	7,860.5
Non-current liabilities		
Provisions	0.3	0.3
Total non-current liabilities	**0.3**	0.3
Current liabilities		
Current liabilities	7.9	16.2
Payables to group companies	77.8	13.5
Total current liabilities	**85.7**	29.7
Total liabilities	**86.0**	30.0
TOTAL EQUITY AND LIABILITIES	**7,890.6**	7,890.5
Pledged assets	5,670.6	8,717.8

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2015– 30 Sep 2015 9 months**	**1 Jul 2015– 30 Sep 2015 3 months**	1 Jan 2014— 30 Sep 2014 9 months	1 Jul 2014— 30 Sep 2014 3 months	1 Jan 2014— 31 Dec 2014 12 months
Cash flow from operations					
Net result	-55.9	-15.3	-101.1	-23.2	108.7
Adjustment for non-cash related items	0.1	—	-0.2	-0.3	-36.7
Changes in working capital	56.1	14.2	184.8	196.8	11.0
Total cash flow from operations	**0.3**	**-1.1**	83.5	173.3	83.0
Cash flow from investments					
Change in other fixed assets	—	—	-0.1	-0.1	-0.1
Total Cash flow from investments	**–**	**–**	-0.1	-0.1	-0.1
Cash flow from financing					
Change in long-term liabilities	—	—	-21.7	-175.6	-21.7
Purchase of own shares	—	—	-62.2	—	-62.2
Total cash flow from financing	**–**	**–**	-83.9	-175.6	-83.9
Change in cash and cash equivalents	0.3	-1.1	-0.5	-2.4	-1.0
Cash and cash equivalents at the beginning of the period	1.8	2.9	2.6	4.6	2.6
Currency exchange difference in cash and cash equivalents	-0.2	0.1	0.2	0.1	0.2
Cash and cash equivalents at the end of the period	**1.9**	**1.9**	2.3	2.3	1.8

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 2014	**3.2**	**861.3**	**2,357.5**	**4,592.0**	**6,949.5**	**7,814.0**
Total comprehensive income	**–**	**–**	**–**	**-101.1**	**-101.1**	**-101.1**
Transactions with owners						
Purchase of own shares	–	–	-62.2	–	-62.2	-62.2
Total transactions with owners	**–**	**–**	**-62.2**	**–**	**-62.2**	**-62.2**
Balance at 30 September 2014	**3.2**	**861.3**	**2,295.3**	**4,490.9**	**6,786.2**	**7,650.7**
Total comprehensive income	**–**	**–**	**–**	**209.8**	**209.8**	**209.8**
Balance at 31 December 2014	**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**

In 2014 the Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount. The amounts were recognised against other reserves. In consequence the cancellation of shares did not impact the Company’s share capital.

Key Financial Data

Financial data (MUSD)	1 Jan 2015– 30 Sep 2015 9 months	1 Jul 2015– 30 Sep 2015 3 months	1 Jan 2014 – 30 Sep 2014 9 months	1 Jul 2014 – 30 Sep 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Revenue	433.3	154.2	650.0	189.2	785.2
EBITDA	291.1	98.7	506.9	157.6	671.3
Net result	-372.6	-201.6	5.1	4.3	-431.9
Operating cash flow	524.3	177.0	804.0	307.0	1,138.5
Data per share (USD)					
Shareholders' equity per share	0.00	0.00	3.46	3.46	1.40
Operating cash flow per share	1.70	0.57	2.57	0.97	3.68
Cash flow from operations per share	0.14	0.23	1.88	0.61	1.91
Earnings per share	-1.19	-0.65	0.03	0.02	-1.38
Earnings per share fully diluted	-1.19	-0.65	0.03	0.02	-1.38
EBITDA per share	0.94	0.32	1.62	0.49	2.17
Dividend per share	–	–	–	–	–
Number of shares issued at period end	311,070,330	311,070,330	311,070,330	311,070,330	311,070,330
Number of shares in circulation at period end	309,070,330	309,070,330	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period	309,070,330	309,070,330	312,537,337	309,070,330	309,170,986
Weighted average number of shares for the period fully diluted	309,854,784	309,854,784	312,689,363	309,222,356	309,475,038
Share price					
Quoted price at period end (SEK)	107.80	107.80	122.10	122.10	112.40
Key ratios					
Return on equity (%)	-151	-81	0	0	-50
Return on capital employed (%)	-1	0	8	4	-11
Net debt/equity ratio (%)	422,975	422,975	192	192	605
Equity ratio (%)	1	1	20	20	9
Share of risk capital (%)	17	17	45	45	28
Interest coverage ratio	-1	0	17	21	-13
Operating cash flow/interest ratio	10	8	60	55	49
Yield	–	–	–	–	–

Key Ratio Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Financial Information

The financial information relating to the nine month period ended 30 September 2015 has not been subject to review by the auditors of the Company.

Stockholm, 4 November 2015

Alex Schneiter
President and CEO

The Company will publish the following reports:

- The year end report (January — December 2015) will be published on 3 February 2016.
- The three month report (January — March 2016) will be published on 11 May 2016.

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

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

Forward-Looking Statements
Certain statements made and information contained herein constitute "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Company's future performance, business prospects or opportunities. Forward-looking statements include, but are not limited to, statements with respect to estimates of reserves and/or resources, future production levels, future capital expenditures and their allocation to exploration and development activities, future drilling and other exploration and development activities. Ultimate recovery of reserves or resources are based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management.

All statements other than statements of historical fact may be forward-looking statements. Statements concerning proven and probable reserves and resource estimates may also be deemed to constitute forward-looking statements and reflect conclusions that are based on certain assumptions that the reserves and resources can be economically exploited. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations and assumptions will prove to be correct and such forward-looking statements should not be relied upon. These statements speak only as on the date of the information and the Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws. These forward-looking statements involve risks and uncertainties relating to, among other things, operational risks (including exploration and development risks), productions costs, availability of drilling equipment, reliance on key personnel, reserve estimates, health, safety and environmental issues, legal risks and regulatory changes, competition, geopolitical risk, and financial risks. These risks and uncertainties are described in more detail under the heading "Risks and Risk Management" and elsewhere in the Company's annual report. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. Actual results may differ materially from those expressed or implied by such forward-looking statements. Forward-looking statements are expressly qualified by this cautionary statement.

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