Lundin Petroleum

Q4

YEAR END REPORT 2015

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Twelve months ended 31 December 2015 (31 December 2014)

- Production of 32.3 Mboepd (23.8 Mboepd)[1]
- Revenue of MUSD 569.3 (MUSD 785.2)
- EBITDA of MUSD 384.7 (MUSD 671.3)
- Operating cash flow of MUSD 699.6 (MUSD 1,138.5)
- Net result of MUSD -866.3 (MUSD -431.9) including a net foreign exchange loss of MUSD -507.3 and an after tax impairment charge of MUSD -296.3
- Net debt of MUSD 3,786 (31 December 2014: MUSD 2,609)
- Edvard Grieg facilities successfully installed offshore Norway and first oil was achieved in November 2015.
- The Bøyla field, Norway and the Bertam field, Malaysia commenced production in January and April 2015 respectively.
- 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 and sidetrack wells 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.

Fourth quarter ended 31 December 2015 (31 December 2014)

- Production of 38.3 Mboepd (22.0 Mboepd)[1]
- Revenue of MUSD 136.0 (MUSD 135.2)
- EBITDA of MUSD 93.6 (MUSD 164.4)
- Operating cash flow of MUSD 175.4 (MUSD 334.5)
- Net result of MUSD -493.7 (MUSD -437.0) including a net foreign exchange loss of MUSD -129.2 and an after tax impairment charge of MUSD -296.3

	1 Jan 2015–31 Dec 2015 12 months	1 Oct 2015–31 Dec 2015 3 months	1 Jan 2014–31 Dec 2014 12 months	1 Oct 2014–31 Dec 2014 3 months
Production in Mboepd[1]	32.3	38.3	23.8	22.0
Revenue in MUSD	569.3	136.0	785.2	135.2
Net result in MUSD	-866.3	-493.7	-431.9	-437.0
Net result attributable to shareholders of the Parent Company in MUSD	-861.7	-492.5	-427.2	-436.0
Earnings/share in USD[2]	-2.79	-1.59	-1.38	-1.41
Earnings/share fully diluted in USD[2]	-2.78	-1.59	-1.38	-1.41
EBITDA in MUSD	384.7	93.6	671.3	164.4
Operating cash flow in MUSD	699.6	175.4	1,138.5	334.5

[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,

We continue to witness extreme volatility in oil prices with falls to levels not seen in over a decade and it is clear to me that the battle for market share is approaching its final conclusion. At current price levels I believe a rebalancing of supply and demand is inevitable and likely to take place during the second half of 2016 as higher cost producers are forced to curtail production levels. We know from our own experience that unique and highly prized assets such as Johan Sverdrup are not discovered every day and it is only fields with these characteristics that can be developed at current price levels. All fields face natural decline and therefore the significant investment cuts and project deferrals that we have seen will ultimately lead to a recovery in oil prices.

That being said we must face the realities of low oil prices and the best strategy in such market conditions is to execute on and deliver a low cost asset base. That is exactly what we are doing.

It makes me very proud to report that our Company passed a significant milestone by achieving first oil from Edvard Grieg at the end of November. We delivered this project ahead of our latest guidance, and more importantly it was delivered safely and within budget. Initial performance is very encouraging and ahead of our expectations in terms of facilities uptime and well productivity. This has been a remarkable achievement by our Norwegian project team, our contractors and subcontractors and would not have been possible without the excellent support received from our partners and the government in Norway. Edvard Grieg marks the beginning of a transformational increase in Lundin Petroleum's production levels and cash flow generation going forward. I am also pleased to report that we met our revised production forecast of 32,000 boepd for the full year.

Our Company is in strong health with reserves of close to 700 MMboe and a production base that will grow significantly. Our cost of operations will fall below USD 10 per barrel and with strong access to liquidity to withstand the current low oil price environment we will emerge from this downturn as a company that is stronger than ever.

Recently, Statoil announced the acquisition of a minority shareholding in Lundin Petroleum, corresponding to 11.93 percent of the shares outstanding. Statoil has stated that there is no further plan to increase their shareholding in the Company and that they are supportive of Lundin Petroleum's management, its Board of Directors and its strategy. We welcome Statoil as a long-term shareholder of Lundin Petroleum and we view such an investment as a testimony of the unique and very valuable portfolio which the Company has built during this last decade. We are looking forward to continue to successfully work together with Statoil as a partner with the ultimate objective to further enhance the value of our key assets such as Edvard Grieg and Johan Sverdrup.

Edvard Grieg and production

Edvard Grieg commenced production on 28 November 2015 and since then has achieved a remarkable average uptime of 95 percent. Initial productivity per well has also exceeded expectations. This excellent performance has allowed us to achieve spot production rates in excess of 90,000 boepd when our third Edvard Grieg production well was brought on stream. In addition, following successful field appraisal, we have been able to book an additional 20 MMboe of gross 2P reserves on the Edvard Grieg field bringing the total gross field reserves to 206 MMboe.

Our fourth quarter production averaged 38,300 boepd and was slightly ahead of our guidance. The positive impact of the Edvard Grieg field coming onstream earlier than forecast was partially offset by facilities related issues on the Alvheim FPSO which have now been resolved. The Alvheim FPSO continues to provide excellent uptime and reliability with production efficiency of 94 percent for 2015.

The Brynhild field delivered production in line with our guidance for the second half of 2015, however achieving consistent levels of uptime performance remains challenging. The Brynhild subsurface data acquired so far from the producing wells suggests the connected volume is significantly lower than was predicted in our Plan of Development. This downward revision to Brynhild reserves has however been offset by positive revisions to our Alvheim area and Edvard Grieg reserves.

For 2016 our production guidance is between 60,000 and 70,000 boepd. This equates to a doubling of 2015 levels. The Edvard Grieg field is today the largest contributor of Lundin Petroleum's production growth until the Johan Sverdrup field comes onstream towards the end of 2019. Edvard Grieg will reach its plateau production as planned during the second half of 2016.

Our cost of operations for the full year remains low and was below forecast at approximately USD 10.25 per barrel. Our costs of operations for 2016 are forecast at USD 8.25 per barrel for the full year.

Johan Sverdrup development

The execution of the Johan Sverdrup Phase 1 development is going according to plan. More importantly, we continue to see the benefit of the current market conditions and the impact of the low oil price environment on costs. Statoil, the operator of the Johan Sverdrup field, have reported further cost reductions for Phase 1 which is now estimated at NOK 108.5 billion compared to the original plan of development estimate of NOK 123 billion; a downwards revision of 12 percent. Furthermore, debottlenecking measures have been approved with the aim to increase Phase 1 production capacity.

Significant progress has also been achieved towards the concept definition of Phase 2. This has resulted in further savings with the total full field capital expenditure now estimated at between NOK 160 to 190 billion (real) compared to the original plan of development full field estimate of NOK 170 to 220 billion. Phase 2 concept selection is anticipated to be made towards the end of 2016.

Johan Sverdrup is ideally positioned to take the full benefit of this challenging environment and corresponding low oil price. There is no better time to go in the market and award contracts. I anticipate we will see further cost savings in Johan Sverdrup which will further improve the economics of this world class project.

Exploration and appraisal

We continue to be active on the exploration front with particular focus on the southern Barents Sea, the Utsira High and the Sabah area in Malaysia. During the fourth quarter we announced a new discovery, Rolvsnes, located just south of the Edvard Grieg field and on trend with the Luno South discovery. Studies are ongoing to establish the commerciality of these discoveries as potential tie-back to the Edvard Grieg facilities.

Although it is fair to say that overall our fourth quarter exploration track record has been disappointing I remain confident in our ability to continue to find new resources with the quality and potential to create value within our own core exploration areas. Overall, we have demonstrated that with a focused approach, innovative and creative thinking and a long term strategy of organic growth, we will continue to generate significant shareholder value with our average finding costs in Norway remaining well below USD 1 per barrel.

In 2016 our strategy remains unchanged and our main focus will be the southern Barents Sea where we will be active on both fronts; exploration and appraisal with a particular focus on the existing Alta discovery area. I firmly believe that the southern Barents Sea potential is significant and this is a region where the Company will dedicate significant resources for the years to come. Further exploration drilling will also be taking place on the Utsira High and in the Sabah area in Malaysia.

2016 objectives

Our 2016 objectives are very clear. First of all, we will maximise our existing operational efficiency to establish a solid foundation of strong cash flow for the next growth phase of the Company. Capital and operational efficiency is in the forefront of our minds. We are also embracing the low oil price environment as a time of opportunity when it comes to our operations. Secondly, we will continue to work very hard to maintain a robust balance sheet and strong access to liquidity. Capital discipline will be a major focus in these challenging times. This will also allow us to maintain an opportunistic attitude and take full advantage of the current deflationary environment. Thirdly, we will continue to play a proactive role towards the execution of the Johan Sverdrup field and provide all the support required at the partnership level to maximise the ultimate profitability of this world class asset. Finally, our organic growth strategy remains intact and we will continue to explore for new resources. In this environment, though, we will maintain a very disciplined and focused approach, which, in actual fact, has been very successful in the past, leading to great discoveries and value creation.

It goes without saying that these objectives will be realised without compromising on the health and safety of our people and our responsibility to our stakeholders. As we enter a new phase of significant growth I am confident in our ability to take full advantage of this challenging environment. Ultimately, this is about positioning the Company to deliver sustainable value driven transformation. This transformation is possible with the enthusiasm and hardworking culture embedded in the Company. I am very grateful for the continued support from you fellow shareholders, the Board and the whole team at Lundin Petroleum.

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 3 February 2016

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 financial year of 2015 accounting for 64 percent of total production and with 95 percent of Lundin Petroleum's total reserves.

Reserves and Resources

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

Production

Production for the year amounted to 32.3 thousand barrels of oil equivalents per day (Mboepd) (compared to 23.8 Mboepd over the same period in 2014) and was comprised as follows:

Production in Mboepd	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Crude oil				
Norway	18.6	21.1	15.0	14.2
France	2.7	2.5	2.9	2.8
Malaysia	5.5	9.3	–	–
Total crude oil production	**26.8**	**32.9**	17.9	17.0
Gas				
Norway	2.1	2.3	2.6	2.2
Netherlands	1.8	1.7	1.9	1.8
Indonesia	1.6	1.4	1.4	1.0
Total gas production	**5.5**	**5.4**	5.9	5.0
Total production				
Quantity in Mboe	**11,790.3**	**3,526.6**	8,688.8	2,024.6
Quantity in Mboepd	**32.3**	**38.3**	23.8	22.0

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– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Alvheim	15%	7.8	7.2	9.6	9.8
Volund	35%	4.9	4.0	7.4	6.1
Bøyla	15%	2.1	2.0	–	–
Brynhild	90%	4.2	4.3	0.1	0.5
Edvard Grieg	50%	1.4	5.6	–	–
Gaupe	40%	0.3	0.3	0.5	–
		20.7	**23.4**	17.6	16.4

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

The Edvard Grieg field commenced production on 28 November 2015 with average production for the year of 1,400 barrels of oil equivalent per day (boepd). The field initially started production from one well with the second and third production wells commencing production in December 2015 and January 2016 respectively. The production performance from the first three wells has exceeded expectations with gross well production capacity in excess of 90,000 boepd. The facilities uptime performance has also been exceptional with an average uptime of 95 percent achieved so far. Nevertheless, as per the reservoir management plan the 2016 production levels will be held below the well potential until sufficient water injection wells become available to balance production levels with available injection. Additionally, the average facilities uptime during 2016 is expected to be lower than what has been achieved to date, as certain downtime is expected in relation to remaining commissioning activities and the tie-in of the Ivar Aasen field during the fourth quarter of 2016. The next two development wells will be drilled as water injection wells with the fourth production well expected to be drilled and put into production during the second half of 2016 when the field is forecast to achieve its gross plateau production of 100,000 boepd.

Production from the Alvheim field during the year was marginally below forecast. Production levels have been somewhat restricted due to maintenance work on one of the gas compressors on the Alvheim FPSO during the early part of the year and also during the fourth quarter 2015. Alvheim's production level has also been negatively impacted by two wells being shut-in for part of the year 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 uptime also continues to perform at a very high level with an average uptime of 94 percent for the year.

The drilling of two new infill wells on Alvheim has been successfully completed by the Transocean Winner rig during the year with production startup in April 2015 and November 2015. During the year 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. During the fourth quarter 2015 the Alvheim partnership signed a new rig contract to commence in December 2016 with the objective of drilling further infill development wells and a near-field exploration well in the Alvheim area. The cost of operations for the Alvheim field, excluding well intervention work, was below USD 5 per barrel during the year.

The Volund field production during the year 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 two further infill wells are planned to be drilled in 2017. The planned infill drilling on Volund has led to 3 MMboe of net incremental reserves being booked as at 31 December 2015. The cost of operations for the Volund field during the reporting period was below USD 4 per barrel.

The Bøyla field production during the year has been slightly below forecast due to gas compression constraints on the Alvheim FPSO. 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.

Initial production from the Brynhild field, 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. One further water injection well has also been completed. As previously disclosed Brynhild production guidance was revised downward during the year due to poor facilities uptime on the Haewene Brim FPSO and poorer than anticipated reservoir performance. Production during the year met the revised guidance. While facilities uptime has improved significantly through the year reliability issues with the water injection system continue. The water injection system has been successfully tested and it is expected that reliability will improve through the early part of 2016. Brynhild reservoir performance indicates reduced connected hydrocarbon volumes compared to the original estimate and this has resulted in gross ultimate recoverable reserves in Brynhild being reduced to 7.4 MMboe. Projections of Brynhild performance reflect both a reduced expectation on facilities performance and the revised reserve estimate.

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	206 MMboe	28 November 2015	100.0 Mboepd
Various	Ivar Aasen	1.385%	Det norske	May 2013	183 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 commenced production on 28 November 2015. The offshore commissioning and hook-up activities were completed ahead of schedule and the flotel Safe Boreas left the Edvard Grieg facilities in December 2015.

A number of milestones have been achieved during the year. 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 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 year. Development drilling commenced during the third quarter of 2014 with the Rowan Viking jack-up rig with the first three production wells successfully put into production. The Rowan Viking rig is scheduled to drill another 11 development wells and is anticipated to remain on location up to end 2017.

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 have resulted in gross ultimate recoverable reserves for Edvard Grieg increasing from 187 to 206 MMboe.

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 pipelines installation between Ivar Aasen and Edvard Grieg was completed during the third quarter of 2015. The topside construction is approximately 93 percent complete with mechanical completion expected during the first half of 2016. The topsides installation is scheduled during the summer of 2016. Ivar Aasen is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

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

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.

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

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 of 2016.

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

Appraisal

2015 appraisal well programme

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

During the year 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 4 km south of the discovery well 7220/11-1 and 3 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 east 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 deepen the well and perform a well test.

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	Oil discovery
Southern Barents Sea						
PL708	7130/4-1	November	Ørnen	40%	Lundin Petroleum	Dry
PL609	7220/6-2	October	Neiden	40%	Lundin Petroleum	Suspended
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	6407/10-4	November	Lorry	40%	Lundin Petroleum	Dry

Lundin Petroleum has completed seven exploration wells in Norway during the year and has in addition suspended one well for re-entry during 2016. The Lorry well was completed in January 2016.

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 metres 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 metres 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.

The drilling of the Neiden well in PL609 in the southern Barents Sea commenced in October 2015. Due to the rig being restricted in terms of operating in the Barents Sea during the winter months the well had to be suspended in November 2015 without reaching reservoir depth. The well is planned to be re-entered in 2016 to complete the drilling operations.

In December 2015 the Rolvsnes prospect in PL338C just south of the Edvard Grieg field was announced as an oil discovery with estimated gross contingent resources of between 3 to 16 MMboe. The discovery was made in granitic basement and the well flow tested oil at 265 bopd. There remains significant resource upside including potential to find a more extensive fracture network and secondary recovery potential. Including this prospective upside potential the total gross resource estimate is between 10 and 46 MMboe.

The Ørnen exploration well in PL708 drilled in the eastern Barents Sea was completed in December 2015 as a dry hole. The well encountered three reservoir horizons with minor non-commercial gas volumes encountered in the Lower Carboniferous sandstones. The well was plugged and abandoned as a dry hole.

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

Lundin Petroleum will drill three exploration wells offshore Norway during 2016 targeting net unrisked prospective resources of approximately 250 MMboe. In addition to the Neiden re-entry the 2016 drilling schedule includes the Fosen prospect in PL544 (WI 40%) in the Utsira High and the Filicudi prospect in PL533 (WI 35%) just south of the Johan Castberg discovery in the southern Barents Sea.

Licence awards, transactions and relinquishments

In 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.

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

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

During the year, Lundin Petroleum farmed out 30 percent in PL338C (WI 50% after farm-out), 30 percent in PL544 (WI 40% after farm-out), 75 percent in PL006C (WI 0% after farm-out) and 30 percent in PL410 (WI 52.352% after farm-out) to Lime Petroleum Norway. During the year licences PL490, PL641, PL646, PL639, PL584 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. 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– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
France					
– Paris Basin	100%[1]	2.3	2.2	2.5	2.4
– Aquitaine	50%	0.4	0.3	0.4	0.4
Netherlands	Various	1.8	1.7	1.9	1.8
		4.5	**4.2**	4.8	4.6

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

France
Production levels during the year 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. Trucking operations have commenced and will remain in place for the duration of 2016.

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 have been finalised and the wells have commenced production according to expectations.

The Netherlands
Production from the Netherlands has been ahead of forecast during the year 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 year 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 year, 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– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Bertam	75%	**5.5**	**9.3**	–	–

Offshore, Peninsular Malaysia
Production levels from the Bertam field in PM307 (WI 75%) during the year have been slightly below 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 of 98 percent 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 successful Bertam-3 appraisal well which confirmed additional resources in the northeastern part of the field. A long-reach horizontal development well will be drilled into the Bertam-3 area from the Bertam wellhead platform early in 2016 and put into production immediately after completion. 11 wells are currently in production. The Bertam field is estimated to contain gross remaining reserves as at 31 December 2015 of 14.3 MMboe. The project was completed safely, on schedule and on budget.

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 non-commercial gas discovery with 9 metres of high quality reservoir sands.

During the year 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 subsequently drilled the Selada prospect straddling Blocks PM307 (WI 75%) and PM308A (WI 75%) however the well failed to encounter any hydrocarbons and the well was plugged and abandoned as a dry hole.

Offshore Sabah, East Malaysia

Lundin Petroleum completed the drilling of the Imbok well on SB307/308 (WI 65%) in early January 2016. The well encountered only oil shows in Miocene sands and was plugged and abandoned as a dry hole. Following the Imbok well the rig was moved to drill the Bambazon prospect also on SB307/308, which encountered 15 metres of net reservoir pay with oil shows. However no moveable oil was recovered from sampling and the well has been plugged and abandoned as a dry hole. The West Prospero rig has subsequently moved to the Maligan prospect on SB307/308 targeting gross 110 MMboe of unrisked prospective resources with the well currently drilling ahead.

Lundin Petroleum signed a farmout agreement with Dyas in December 2015 whereby Lundin Petroleum will farmout a 20 percent working interest in SB307/308 (WI 65% after farm-out), a 20 percent working interest in SB303 (WI 55% after farm-out) and a 15 percent working interest in PM328 (WI 35% after farm-out) located offshore Peninsular Malaysia. The farmout agreement, which is subject to approval from relevant authorities, took effect ahead of the drilling of the Imbok and Bambazon exploration wells on SB307/308.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Singa	25.9%	**1.6**	**1.4**	1.4	1.0

The production from the Singa field has been substantially in line with forecast during the year. 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 half 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

As this was a very active year for Lundin Petroleum from an operational point of view, Lundin Petroleum put a strong emphasis on responsible and safe operations.

Management and personnel were required to follow a Corporate Responsibility e-learning, in order to reinforce their understanding of their respective roles and responsibilities within the Group. In the process of expanding and communicating Lundin Petroleum's corporate responsibility commitment, the Group issued a Contractor Declaration to ensure that contractors work in accordance with the Company's requirements in relation to health, safety and environment (HSE), labour standards, human rights, and anti-corruption.

The high level of activities in 2015, in particular in relation to the construction completion and start of production of the two significant fields, Edvard Grieg in Norway and Bertam in Malaysia, resulted in a Lost Time Incident rate of 0.35 per 200,000 hours and a Total Recordable Incident rate of 0.74. There were no serious personnel, process or environmental incidents throughout the year.

FINANCIAL REVIEW

Result

The net result for the financial year 2015 amounted to MUSD -866.3 (MUSD -431.9). The loss was mainly driven by lower oil prices, exploration and impairment costs and higher finance costs as a result of the strong US Dollar during the year generating a largely non-cash foreign exchange loss. The net result attributable to shareholders of the Parent Company for the year amounted to MUSD -861.7 (MUSD -427.2) representing earnings per share of USD -2.79 (USD -1.38).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the year amounted to MUSD 384.7 (MUSD 671.3) representing EBITDA per share of USD 1.24 (USD 2.17). Operating cash flow for the year amounted to MUSD 699.6 (MUSD 1,138.5) representing operating cash flow per share of USD 2.26 (USD 3.68).

Changes in the Group

There have been no significant changes in the Group during the year.

Revenue

Revenue for the year amounted to MUSD 569.3 (MUSD 785.2) 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 year amounted to MUSD 521.0 (MUSD 745.0). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 50.71 (USD 88.28) and is detailed in the following table. The average Dated Brent price for the year amounted to USD 52.39 (USD 98.95) per barrel.

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

Sales Average price per boe expressed in USD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Crude oil sales				
Norway				
– Quantity in Mboe	5,939.4	999.5	5,183.3	1,181.5
– *Average price per boe*	*52.97*	*43.63*	*102.35*	*71.08*
France				
– Quantity in Mboe	971.4	203.0	1,028.7	223.8
– *Average price per boe*	*52.07*	*36.00*	*94.08*	*57.63*
Netherlands				
– Quantity in Mboe	1.2	–	1.1	–
– *Average price per boe*	*50.20*	–	*91.64*	–
Malaysia				
– Quantity in Mboe	1,455.6	612.8	–	–
– *Average price per boe*	*48.92*	*44.01*	–	–
Total crude oil sales				
– Quantity in Mboe	**8,367.6**	**1,815.3**	6,213.1	1,405.3
– Average price per boe	***52.16***	***42.91***	*100.98*	*68.94*
Gas and NGL sales				
Norway				
– Quantity in Mboe	745.7	176.0	1,080.8	215.8
– *Average price per boe*	*44.21*	*36.23*	*56.02*	*56.65*
Netherlands				
– Quantity in Mboe	633.3	159.4	687.9	161.4
– *Average price per boe*	*38.88*	*33.60*	*51.11*	*49.93*
Indonesia				
– Quantity in Mboe	527.7	115.0	457.2	83.4
– *Average price per boe*	*50.99*	*51.49*	*47.87*	*46.95*
Total gas and NGL sales				
– Quantity in Mboe	**1,906.7**	**450.4**	2,225.9	460.6
– *Average price per boe*	***44.31***	***39.19***	*52.83*	*52.55*
Total sales				
– Quantity in Mboe	**10,274.3**	**2,265.7**	8,439.0	1,865.9
– Average price per boe	***50.71***	***42.17***	*88.28*	*64.89*

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

The change in under/over lift position amounted to a net credit of MUSD 25.6 (MUSD 23.4) in the year. There was an underlift of entitlement movement on the Norwegian producing fields during the year due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 22.7 (MUSD 16.8) for the year and included Bertam FPSO lease income, a quality differential compensation on Alvheim blended crude, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the year amounted to MUSD 150.3 (MUSD 66.5) and are detailed in the table below.

Production costs	1 Jan 2015– 31 Dec 2015 12 months	1 Oct 2015– 31 Dec 2015 3 months	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Cost of operations				
– In MUSD	121.1	32.8	94.4	22.2
– In USD per boe	*10.27*	*9.31*	*10.86*	*10.95*
Tariff and transportation expenses				
– In MUSD	11.8	3.7	18.4	3.4
– In USD per boe	*1.00*	*1.05*	*2.12*	*1.68*
Royalty and direct production taxes				
– In MUSD	3.5	0.9	3.6	0.8
– In USD per boe	*0.29*	*0.25*	*0.41*	*0.39*
Change in inventory position				
– In MUSD	-12.6	-6.8	-0.8	-1.3
– In USD per boe	*-1.07*	*-1.94*	*-0.09*	*-0.66*
Other				
– In MUSD	26.5	5.1	-49.1	-63.3
– In USD per boe	*2.25*	*1.46*	*-5.65*	*-31.26*
Total production costs				
– In MUSD	**150.3**	**35.7**	66.5	-38.2
– In USD per boe	***12.74***	***10.13***	*7.65*	*-18.90*

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

The total cost of operations for the year was MUSD 121.1 (MUSD 94.4). The year included costs of MUSD 7.3 associated with well intervention work on the Alvheim field and MUSD 7.7 on the Brynhild field mainly in relation to its share of the replacement cost of the mooring lines and other necessary work on the FPSO facilities. The total cost of operations excluding operational projects amounted to MUSD 102.7 (MUSD 72.3). The increase compared to last year is attributable to the contribution to the operating costs of the Brynhild, Bøyla, Bertam and Edvard Grieg fields in 2015, partly offset by the impact of the stronger US Dollar on the funding of non-US Dollar denominated expenditures in the year.

The cost of operations per barrel including operational projects amounted to USD 10.27 (USD 10.86) for the year and excluding operational projects, the cost of operations amounted to USD 8.71 (USD 8.32) per barrel. The cost of operations per barrel amounts are both lower than the third quarter guidance for 2015.

Tariff and transportation expenses for the year amounted to MUSD 11.8 (MUSD 18.4). The decrease compared to last year is mainly due to lower volumes from the Volund and Gaupe fields in the year as well as the stronger US Dollar impact.

Other costs amounted to MUSD 26.5 (credit of MUSD 49.1) and mainly related to the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price curve at the end of 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 and decommissioning costs amounted to MUSD 260.6 (MUSD 131.6) and are detailed in Note 3. Depletion costs associated with oil and gas properties amounted to MUSD 258.0 (MUSD 131.6) at an average rate of USD 21.88 (USD 15.14) per barrel. The higher depletion costs for the year compared to last year is due to the contributions of the Brynhild, Bøyla, Bertam and Edvard Grieg fields, partly offset by lower production volumes on the Alvheim and Volund fields in the year. Decommissioning costs charged to the income statement in the year amounted to MUSD 2.6 (MUSD —) and related to the increase in the site restoration estimate for the Gaupe field.

Depletion of other assets amounted to MUSD 23.7 (MUSD —) for the year and related to the Bertam FPSO.

Exploration costs

Exploration costs expensed in the income statement for the year amounted to MUSD 184.1 (MUSD 386.4) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the fourth quarter of 2015, exploration costs relating to Norway of MUSD 31.2 were mainly related to the unsuccessful well that was drilled in PL708 (Ørnen) and exploration costs relating to Malaysia of MUSD 36.3 were mainly related to the unsuccessful wells that were drilled in PM308A (Selada) and PM307 (Mengkuang).

Impairment costs

Impairment costs charged to the income statement for the year amounted to MUSD 737.0 (MUSD 400.7). Due to the significantly lower forward oil price curve at the end of 2015 and a reserves downgrade, a non-cash pre-tax impairment charge of MUSD 526.0 was recognised against the Brynhild field, Norway. A deferred tax credit of MUSD 416.1 on the Brynhild field impairment was recognised in the income statement yielding a net after tax charge of MUSD 109.9. On the Bertam field, Malaysia, a non-cash pre-tax impairment cost of MUSD 165.9 and an associated MUSD 24.6 deferred tax credit were recognised, mainly due to the lower forward oil price curve, yielding a net after tax charge of MUSD 141.3. Further impairments were taken on Malaysian and Indonesian exploration blocks amounting to MUSD 25.9 and MUSD 19.2 respectively.

General, administrative and depreciation expenses

The general administrative and depreciation expenses for the year amounted to MUSD 39.5 (MUSD 52.2) which included a charge of MUSD 7.1 (MUSD 8.9) in relation to the Group’s long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the year amounted to MUSD 5.2 (MUSD 4.8).

Finance income

Finance income for the year amounted to MUSD 7.4 (MUSD 1.8) and is detailed in Note 4. Interest income for the year 2015 amounted to MUSD 6.1 and included interest on the Norwegian exploration tax refund and on the Johan Sverdrup unitisation past cost settlement received during the fourth quarter of 2015.

Finance costs

Finance costs for the year amounted to MUSD 617.9 (MUSD 421.8) and are detailed in Note 5.

Interest expenses for the year amounted to MUSD 71.4 (MUSD 21.1) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 40.2 (MUSD 36.6) associated with the funding of the Norwegian and Malaysian development projects was capitalised in the year.

Net foreign exchange losses for the year amounted to MUSD 507.3 (MUSD 356.3). 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 year 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 year, 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 year, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 132.7 (MUSD 22.8).

The amortisation of the deferred financing fees amounted to MUSD 12.4 (MUSD 12.6) for the year 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 year amounted to MUSD 7.7 (MUSD 21.4) with the decrease compared to last year being due to the increased borrowings under the financing arrangements.

Tax

The overall tax credit for the year amounted to MUSD 570.1 (MUSD 253.2).

The current tax credit for the year amounted to MUSD 280.6 (MUSD 419.7) which included MUSD 283.3 (MUSD 431.7) relating to the Norway exploration tax refund due to the significant level of development and exploration and appraisal expenditure in Norway in the year and the tax depreciation on development expenditure incurred in prior years. The current tax credit in Norway for the year is partly offset by the current tax charge relating to other Group operations.

The deferred tax credit for the year amounted to MUSD 289.5 (charge of MUSD 166.5) which predominantly related to Norway. The deferred tax charge or credit arises primarily where there is a difference in depletion for tax and accounting purposes.
A deferred tax credit of MUSD 440.7 in relation to the Brynhild and Bertam fields impairment charges was recognised in the fourth quarter of 2015.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 and 78 percent. The effective tax rate for the year is affected by items which do not receive a full tax credit such as the reported net foreign exchange loss and Malaysian and Indonesian impairment charges, 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 year amounted to MUSD -4.6 (MUSD -4.7) 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 4,015.4 (MUSD 4,182.6) and are detailed in Note 7.

Development and exploration and appraisal expenditure incurred for the financial year 2015 was as follows:

Development expenditure in MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014– 31 Dec 2014 12 months	1 Oct 2014– 31 Dec 2014 3 months
Norway	880.7	219.0	1,068.2	249.5
France	16.9	1.0	29.3	14.7
Netherlands	2.7	0.7	3.9	1.1
Indonesia	-1.1	-0.5	-0.8	-0.2
Malaysia	130.1	-4.6	130.6	32.8
	1,029.3	**215.6**	1,231.2	297.9

An amount of MUSD 880.7 (MUSD 1,068.2) of development expenditure was incurred in Norway during the year, primarily on the Edvard Grieg, Brynhild, Ivar Aasen, and Johan Sverdrup field developments. In Malaysia, MUSD 130.1 (MUSD 130.6) was incurred during the year on the Bertam field development.

An amount of MUSD 30.8 (MUSD 118.8) was incurred during the year 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– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014– 31 Dec 2014 12 months	1 Oct 2014– 31 Dec 2014 3 months
Norway	370.2	101.5	572.8	221.3
France	0.4	–	5.9	3.7
Indonesia	3.1	–	47.5	17.5
Malaysia	33.3	25.8	42.7	12.7
Russia	5.3	1.2	4.0	1.4
Other	1.5	0.1	1.6	0.2
	413.8	**128.6**	674.5	256.8

Exploration and appraisal expenditure of MUSD 370.2 (MUSD 572.8) was incurred in Norway during the year, 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 nine exploration wells. In Malaysia, MUSD 33.3 (MUSD 25.8) was incurred during the year principally on the Selada, Mengkuang and Imbok exploration wells.

Other tangible fixed assets amounted to MUSD 204.3 (MUSD 200.3) and included expenditures relating to the Bertam FPSO.

Financial assets amounted to MUSD 10.7 (MUSD 37.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 4.1 (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. Brynhild operating cost share amounted to MUSD 5.5 (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 13.4 (MUSD 12.9) and are mainly related to Malaysia following the impairment of the Bertam field resulting in the depreciable tax pool value being higher than the accounting book value. Previously recognised tax losses in the Netherlands have been released as the losses are not expected to be utilised against future tax liabilities using lower projected gas prices at the year end.

Current assets

Inventories amounted to MUSD 45.6 (MUSD 41.6) and included both well supplies mainly held in Norway and Malaysia and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 159.3 (MUSD 163.5) and are detailed in Note 9. Trade receivables, which are all current, amounted to MUSD 35.2 (MUSD 40.3). Underlift amounted to MUSD 26.5 (MUSD 3.6) and was mainly attributable to a net underlift position in Norway from the fields in the Greater Alvheim Area and the Edvard Grieg field. Joint operations debtors relating to various joint venture receivables amounted to MUSD 48.4 (MUSD 49.1). Prepaid expenses and accrued income amounted to MUSD 29.5 (MUSD 41.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 14.7 (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 5.0 (MUSD 7.4) and included VAT and other miscellaneous receivable balances.

Current tax assets amounted to MUSD 264.7 (MUSD 373.6) and mainly related to the Norwegian corporate tax refund in respect of 2015 which will be received in December 2016. The comparative amount mainly related to the Norwegian corporate tax refund in respect of 2014 which was received in December 2015

Cash and cash equivalents amounted to MUSD 71.9 (MUSD 80.5). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,834.8 (MUSD 2,654.0) and are detailed in Note 10. Bank loans amounted to MUSD 3,858.0 (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 23.2 (MUSD 36.0) and are being amortised over the expected life of the financing facilities.

Provisions amounted to MUSD 379.9 (MUSD 288.0) and are detailed in Note 11. The provision for site restoration amounted to MUSD 368.2 (MUSD 274.1) and related to future decommissioning obligations. The provision has increased during the year 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 542.6 (MUSD 973.3) of which MUSD 407.9 (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. The main reason for the decrease since the prior year is due to the impairment of the Brynhild field resulting in a deferred tax release of MUSD 416.1.

Derivative instruments amounted to MUSD 48.4 (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 32.2 (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 349.9 (MUSD 491.4) and are detailed in Note 12. Deferred revenue amounted to MUSD 20.2 (MUSD —) and represented a payment advanced by the buyer under the Alvheim Blend oil sales contract at the year end. Once the buyer lifts the oil, the liability will be reversed and the revenue will be recognised in the income statement. Joint operations creditors and accrued expenses amounted to MUSD 271.5 (MUSD 383.5) and related mainly to the development and drilling activity in Norway and Malaysia. Other accrued expenses amounted to MUSD 23.7 (MUSD 46.1) and included an amount of MUSD 19.4 in the comparative amount which related 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 during the year. Other current liabilities amounted to MUSD 11.4 (MUSD 9.7).

Derivative instruments amounted to MUSD 66.1 (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 4.8 (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 which was settled during the year. 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 4.8 (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 -78.1 (MSEK 108.7) for the year.

The result included general and administrative expenses of MSEK 89.6 (MSEK 144.9) and finance income of MSEK 4.6 (MSEK 209.9). The prior year included a dividend of MSEK 205.7.

Pledged assets of MSEK 3,569.7 (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 0.5 (MUSD 0.7) from related parties for the provision of office and other services. The Group paid MUSD 0.2 (MUSD 0.6) 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 31 December 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 31 December 2015 is MUSD 427.2 (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.

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. Following the receipt of the 2014 Norwegian exploration tax refund in December 2015, the facility size was reduced to NOK 2.15 billion. As at 31 December 2015, the amount outstanding under the exploration financing facility was zero as the tax refund was used to repay the balance drawn under the facility.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas). Bank guarantees have been issued in support of the work commitments and other related costs in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 31 December 2015 was MUSD 23.5.

Subsequent Events

During the first quarter of 2016, the following items were announced by Lundin Petroleum:

An agreement to sell the FPSO Bertam has been entered into with M3nergy Investment Limited. The deal is subject to completion conditions including finalisation of the purchaser's financing arrangements. The transaction is expected to complete during the first quarter of 2016.

The Lorry exploration well in PL700B, in the southern Norwegian Sea, was plugged and abandoned as a dry hole. The costs of this well will be expensed in the first quarter of 2016.

The Bambazon prospect well on SB307/308, offshore Sabah, Malaysia, encountered oil shows and the well was plugged and abandoned. The costs of this well will be expensed in the first quarter of 2016.

Four exploration licences were awarded to Lundin Petroleum in the Norwegian 2015 APA licensing round, two as operator.

A committed seven year senior secured reserve-based lending facility of up to USD 5.0 billion, with an initial committed amount of USD 4.3 billion, was entered into. This facility replaces the current credit facility of USD 4.0 billion which was due to reduce in availability from June 2016 and mature in 2019.

Share Data
Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 311,070,330 shares with a quota value of SEK 0.01 each. At 31 December 2015 the Company holds 2,000,000 of its own shares.

The Board of directors will propose to the AGM that no dividend will be paid to the shareholders for the financial year 2015.

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 31 December 2015 were 132,836, 247,306 and 438,732 respectively.

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

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

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

The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 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
At 31 December 2015, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
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

At 31 December 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	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 year 2015, the following currency exchange rates have been used.

	31 Dec 2015		31 Dec 2014	
	Average	Period end	Average	Period end
1 USD equals NOK	8.0637	8.8090	6.3011	7.4332
1 USD equals Euro	0.9012	0.9185	0.7526	0.8236
1 USD equals Rouble	61.2881	74.1009	38.3878	59.5808
1 USD equals SEK	8.4303	8.4408	6.8457	7.7366

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2015–31 Dec 2015 12 months	1 Oct 2015–31 Dec 2015 3 months	1 Jan 2014–31 Dec 2014 12 months	1 Oct 2014–31 Dec 2014 3 months
Revenue	1	**569.3**	**136.0**	785.2	135.2
Cost of sales					
Production costs	2	-150.3	-35.7	-66.5	38.2
Depletion and decommissioning costs		-260.6	-84.0	-131.6	-33.2
Depletion of other assets		-23.7	-7.2	–	–
Exploration costs		-184.1	-67.8	-386.4	-256.9
Impairment costs of oil and gas properties		-737.0	-737.0	-400.7	-400.7
Gross profit	3	**-786.4**	**-795.7**	-200.0	-517.4
General, administration and depreciation expenses		-39.5	-8.3	-52.2	-10.2
Operating profit		**-825.9**	**-804.0**	-252.2	-527.6
Result from financial investments					
Finance income	4	7.4	5.7	1.8	0.5
Finance costs	5	-617.9	-162.7	-421.8	-308.8
		-610.5	**-157.0**	-420.0	-308.3
Share of the result of joint ventures accounted for using the equity method		–	–	-12.9	–
Profit before tax		**-1,436.4**	**-961.0**	-685.1	-835.9
Income tax	6	570.1	467.3	253.2	398.9
Net result		**-866.3**	**-493.7**	-431.9	-437.0
Attributable to:					
Owners of the Parent Company		-861.7	-492.5	-427.2	-436.0
Non-controlling interest		-4.6	-1.2	-4.7	-1.0
		-866.3	**-493.7**	-431.9	-437.0
Earnings per share – USD[1]		-2.79	-1.59	-1.38	-1.41
Earnings per share fully diluted – USD[1]		-2.78	-1.59	-1.38	-1.41

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	1 Jan 2015–31 Dec 2015 12 months	1 Oct 2015–31 Dec 2015 3 months	1 Jan 2014–31 Dec 2014 12 months	1 Oct 2014–31 Dec 2014 3 months
Net result	**-866.3**	**-493.7**	-431.9	-437.0
Other comprehensive income				
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	-81.7	-14.7	-196.3	-95.2
Cash flow hedges	6.9	5.6	-148.7	-111.6
Available-for-sale financial assets	-3.7	-0.9	-15.3	-9.0
Other comprehensive income, net of tax	-78.5	-10.0	-360.3	-215.8
Total comprehensive income	**-944.8**	**-503.7**	-792.2	-652.8
Attributable to:				
Owners of the Parent Company	-934.8	-499.6	-766.7	-638.8
Non-controlling interest	-10.0	-4.1	-25.5	-14.0
	-944.8	**-503.7**	-792.2	-652.8

Consolidated Balance Sheet

Expressed in MUSD	Note	31 December 2015	31 December 2014
ASSETS			
Non-current assets			
Oil and gas properties	7	4,015.4	4,182.6
Other tangible fixed assets		204.3	200.3
Financial assets	8	10.7	37.0
Deferred tax assets		13.4	12.9
Total non-current assets		**4,243.8**	4,432.8
Current assets			
Inventories		45.6	41.6
Trade and other receivables	9	159.3	163.5
Current tax assets		264.7	373.6
Cash and cash equivalents		71.9	80.5
Total current assets		**541.5**	659.2
TOTAL ASSETS		**4,785.3**	5,092.0
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		-498.2	431.5
Non-controlling interest		24.1	34.2
Total equity		**-474.1**	465.7
Liabilities			
Non-current liabilities			
Financial liabilities	10	3,834.8	2,654.0
Provisions	11	379.9	288.0
Deferred tax liabilities		542.6	973.3
Derivative instruments	13	48.4	33.9
Other non-current liabilities		32.2	29.1
Total non-current liabilities		**4,837.9**	3,978.3
Current liabilities			
Trade and other payables	12	349.9	491.4
Derivative instruments	13	66.1	101.4
Current tax liabilities		0.7	1.8
Provisions	11	4.8	53.4
Total current liabilities		**421.5**	648.0
Total liabilities		**5,259.4**	4,626.3
TOTAL EQUITY AND LIABILITIES		**4,785.3**	5,092.0

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014— 31 Dec 2014 12 months	1 Oct 2014— 31 Dec 2014 3 months
Cash flows from operating activities				
Net result	-866.3	-493.7	-431.9	-437.0
Adjustments for:				
Exploration costs	184.1	67.8	386.4	256.9
Depletion, depreciation and amortisation	286.9	90.2	136.2	34.1
Current tax	-280.6	-75.1	-419.7	-161.0
Deferred tax	-289.5	-392.2	166.5	-237.9
Impairment of oil and gas properties	737.0	737.0	400.7	400.7
Long-term incentive plans	15.2	3.6	14.5	2.0
Foreign currency exchange loss	374.6	105.0	333.1	261.3
Interest expense	71.3	24.3	21.1	21.1
Other	40.9	6.5	-5.1	-43.9
Interest received	6.1	5.7	0.9	0.4
Interest paid	-110.1	-32.8	-56.5	-18.8
Income taxes received	335.6	335.4	-13.8	-1.5
Changes in working capital	-193.7	-112.6	72.4	-60.1
Total cash flows from operating activities	**311.5**	**269.1**	604.8	16.3
Cash flows from investing activities				
Investment in oil and gas properties	-1,443.3	-344.4	-1,921.2	-570.2
Investment in other fixed assets	-36.0	-1.5	-124.9	-19.0
Disposal of bonds	–	–	10.5	–
Investment in subsidiaries	-0.1	–	–	–
Investment in other shares and participations	-3.7	–	–	–
Share in result in associated company	–	–	11.7	–
Decommissioning costs paid	-10.6	-1.0	-1.2	-0.3
Other payments	-0.5	–	-0.1	–
Total cash flows from investing activities	**-1,494.2**	**-346.9**	-2,025.2	-589.5
Cash flows from financing activities				
Changes in long-term receivables	–	–	9.8	–
Changes in long-term liabilities	1,171.0	95.6	1,419.2	526.3
Financing fees paid	-3.3	-0.1	-20.7	–
Purchase of own shares	–	–	-9.8	–
Distributions	–	–	-0.1	–
Total cash flows from financing activities	**1,167.7**	**95.5**	1,398.4	526.3
Change in cash and cash equivalents	-15.0	17.7	-22.0	-46.9
Cash and cash equivalents at the beginning of the period	80.5	53.0	82.4	111.9
Currency exchange difference in cash and cash equivalents	6.4	1.2	20.1	15.5
Cash and cash equivalents at the end of the period	**71.9**	**71.9**	80.5	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	–	–	-427.2	-427.2	-4.7	-431.9
Other comprehensive income	–	-339.5	–	-339.5	-20.8	-360.3
Total comprehensive income	**–**	**-339.5**	**-427.2**	**-766.7**	**-25.5**	**-792.2**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Value of employee services	–	–	1.0	1.0	–	1.0
Total transactions with owners	**–**	**-9.8**	**1.0**	**-8.8**	**-0.1**	**-8.9**
At 31 December 2014	**0.5**	**8.8**	**422.2**	**431.5**	**34.2**	**465.7**
Comprehensive income						
Net result	–	–	-861.7	-861.7	-4.6	-866.3
Other comprehensive income	–	-73.1	–	-73.1	-5.4	-78.5
Total comprehensive income	**–**	**-73.1**	**-861.7**	**-934.8**	**-10.0**	**-944.8**
Transactions with owners						
Investment in subsidiaries	–	–	–	–	-0.1	-0.1
Value of employee services	–	–	5.1	5.1	–	5.1
Total transaction with owners	**–**	**–**	**5.1**	**5.1**	**-0.1**	**5.0**
At 31 December 2015	**0.5**	**-64.3**	**-434.4**	**-498.2**	**24.1**	**-474.1**

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– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Crude oil	436.5	77.9	627.4	96.9
Condensate	0.6	0.2	3.0	0.2
Gas	83.9	17.5	114.6	24.0
Net sales of oil and gas	**521.0**	**95.6**	745.0	121.1
Change in under/over lift position	25.6	33.3	23.4	9.6
Other revenue	22.7	7.1	16.8	4.5
Revenue	**569.3**	**136.0**	785.2	135.2

Note 2. Production costs MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Cost of operations	121.1	32.8	94.4	22.2
Tariff and transportation expenses	11.8	3.7	18.4	3.4
Direct production taxes	3.5	0.9	3.6	0.8
Change in inventory position	-12.6	-6.8	-0.8	-1.3
Other	26.5	5.1	-49.1	-63.3
	150.3	**35.7**	66.5	-38.2

Note 3. Segment information MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Norway				
Crude oil	314.6	43.6	530.5	84.0
Condensate	–	–	1.7	–
Gas	33.0	6.4	58.8	12.2
Net sales of oil and gas	**347.6**	**50.0**	591.0	96.2
Change in under/over lift position	25.9	33.6	24.4	10.0
Other revenue	2.0	0.4	3.8	0.7
Revenue	**375.5**	**84.0**	619.2	106.9
Production costs	-104.5	-23.4	-11.3	52.6
Depletion and decommissioning costs	-158.9	-49.6	-88.5	-23.6
Exploration costs	-146.5	-31.2	-272.1	-197.9
Impairment costs of oil and gas properties	-526.0	-526.0	-400.7	-400.7
Gross profit	**-560.4**	**-546.2**	-153.4	-462.7

Note 3. Segment information cont. MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
France				
Crude oil	50.6	7.3	96.8	12.9
Net sales of oil and gas	**50.6**	**7.3**	96.8	12.9
Change in under/over lift position	-0.2	-0.2	-0.5	-0.6
Other revenue	1.5	0.4	1.7	0.4
Revenue	**51.9**	**7.5**	98.0	12.7
Production costs	-25.1	-6.3	-33.1	-7.9
Depletion and decommissioning costs	-15.5	-3.5	-16.9	-4.1
Exploration costs	-0.6	–	-4.6	-4.6
Gross profit	**10.7**	**-2.3**	43.4	-3.9
Netherlands				
Crude oil	0.1	–	0.1	–
Condensate	0.6	0.2	1.3	0.2
Gas	24.0	5.2	33.8	7.8
Net sales of oil and gas	**24.7**	**5.4**	35.2	8.0
Change in under/over lift position	-0.1	-0.1	-0.5	0.2
Other revenue	1.8	0.5	2.2	0.5
Revenue	**26.4**	**5.8**	36.9	8.7
Production costs	-12.0	-3.0	-16.8	-4.7
Depletion and decommissioning costs	-10.7	-2.5	-15.9	-3.7
Exploration costs	-0.7	-0.3	-1.4	-0.4
Gross profit	**3.0**	**–**	2.8	-0.1
Malaysia				
Crude oil	71.2	27.0	–	–
Net sales of oil and gas	**71.2**	**27.0**	–	–
Other revenue	10.8	3.8	–	–
Revenue	**82.0**	**30.8**	–	–
Production costs	-4.4	-1.3	–	–
Depletion and decommissioning costs	-66.4	-28.4	–	–
Depletion of other assets	-23.7	-7.2	–	–
Exploration costs	-36.3	-36.3	-14.4	-14.3
Impairment costs of oil and gas properties	-191.8	-191.8	–	–
Gross profit	**-240.6**	**-234.2**	-14.4	-14.3
Indonesia				
Gas	26.9	5.9	22.0	4.0
Net sales of oil and gas	**26.9**	**5.9**	22.0	4.0
Other revenue	–	–	–	–
Revenue	**26.9**	**5.9**	22.0	4.0
Production costs	-4.3	-1.7	-5.4	-1.9
Depletion and decommissioning costs	-9.1	–	-10.3	-1.8
Exploration costs	–	–	-94.2	-40.0
Impairment costs of oil and gas properties	-19.2	-19.2	–	–
Gross profit	**-5.7**	**-15.0**	-87.9	-39.7

Note 3. Segment information cont. MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Other				
Crude oil	–	–	–	–
Net sales of oil and gas	–	–	–	–
Other revenue	6.6	2.0	9.1	2.9
Revenue	**6.6**	**2.0**	9.1	2.9
Production costs	–	–	0.1	0.1
Depletion and decommissioning costs	–	–	–	–
Exploration costs	–	–	0.3	0.3
Gross profit	**6.6**	**2.0**	9.5	3.3

Total				
Crude oil	436.5	77.9	627.4	96.9
Condensate	0.6	0.2	3.0	0.2
Gas	83.9	17.5	114.6	24.0
Net sales of oil and gas	**521.0**	**95.6**	745.0	121.1
Change in under/over lift position	25.6	33.3	23.4	9.6
Other revenue	22.7	7.1	16.8	4.5
Revenue	**569.3**	**136.0**	785.2	135.2
Production costs	-150.3	-35.7	-66.5	38.2
Depletion and decommissioning costs	-260.6	-84.0	-131.6	-33.2
Depletion of other assets	-23.7	-7.2	–	–
Exploration costs	-184.1	-67.8	-386.4	-256.9
Impairment costs of oil and gas properties	-737.0	-737.0	-400.7	-400.7
Gross profit	**-786.4**	**-795.7**	-200.0	-517.4

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

Note 4. Finance income MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Interest income	6.1	5.6	1.2	0.4
Guarantee fees	0.7	–	0.5	0.1
Other	0.6	0.1	0.1	–
	7.4	**5.7**	1.8	0.5

Note 5. Finance costs MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Interest expense	71.4	24.4	21.1	9.4
Foreign currency exchange loss, net	507.3	129.2	356.3	289.5
Result on interest rate hedge settlement	6.9	1.6	2.4	0.7
Unwinding of site restoration discount	10.0	2.5	7.0	1.7
Amortisation of deferred financing fees	12.4	3.1	12.6	2.8
Loan facility commitment fees	7.7	1.0	21.4	4.5
Other	2.2	0.9	1.0	0.2
	617.9	**162.7**	421.8	308.8

Note 6. Income tax MUSD	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Current tax	-280.6	-75.1	-419.7	-161.0
Deferred tax	-289.5	-392.2	166.5	-237.9
	-570.1	**-467.3**	-253.2	-398.9

Note 7. Oil and gas properties MUSD	**31 Dec 2015**	31 Dec 2014
Norway	2,987.5	2,960.7
France	187.0	210.1
Netherlands	31.5	38.6
Malaysia	301.6	428.3
Indonesia	17.6	43.9
Russia	490.2	501.0
	4,015.4	4,182.6

Note 8. Financial assets MUSD	**31 Dec 2015**	31 Dec 2014
Other shares and participations	4.1	4.7
Brynhild operating cost share	5.5	31.0
Other	1.1	1.3
	10.7	37.0

Note 9. Trade and other receivables MUSD	**31 Dec 2015**	31 Dec 2014
Trade receivables	35.2	40.3
Underlift	26.5	3.6
Joint operations debtors	48.4	49.1
Prepaid expenses and accrued income	29.5	41.5
Brynhild operating cost share	14.7	21.6
Other	5.0	7.4
	159.3	163.5

Note 10. Financial liabilities MUSD	**31 Dec 2015**	31 Dec 2014
Non-current:		
Bank loans	3,858.0	2,690.0
Capitalised financing fees	-23.2	-36.0
	3,834.8	2,654.0

Note 11. Provisions

MUSD	31 Dec 2015	31 Dec 2014
Non-current:		
Site restoration	368.2	274.1
Long-term incentive plans	2.2	1.8
Farm-in payment	4.6	7.5
Other	4.9	4.6
	379.9	288.0
Current:		
Farm-in payment	–	48.5
Long-term incentive plans	4.8	4.9
	4.8	53.4
	384.7	341.4

Note 12. Trade and other payables

MUSD	31 Dec 2015	31 Dec 2014
Trade payables	23.1	23.9
Deferred revenue	20.2	–
Joint operations creditors and accrued expenses	271.5	383.5
Other accrued expenses	23.7	46.1
Long-term incentive plans	–	28.2
Other	11.4	9.7
	349.9	491.4

Note 13. Financial instruments
MUSD

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

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

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

31 December 2015 MUSD	Level 1	Level 2	Level 3
Assets			
Cash and cash equivalents	71.9	–	–
Financial assets	10.7	–	–
	82.6	**–**	**–**
Liabilities			
Derivative instruments – non-current	–	48.4	–
Derivative instruments – current	–	66.1	–
	–	**114.5**	**–**

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– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Revenue	**8.7**	**0.3**	9.2	1.6
General and administration expenses	-89.6	-21.7	-144.9	-35.1
Operating profit	**-80.9**	**-21.4**	-135.7	-33.5
Result from financial investments				
Finance income	4.6	0.9	209.9	206.9
Finance costs	-1.8	-1.7	-1.9	—
	2.8	**-0.8**	208.0	206.9
Profit before tax	**-78.1**	**-22.2**	72.3	173.4
Income tax	—	—	36.4	36.4
Net result	**-78.1**	**-22.2**	108.7	209.8

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Net result	**-78.1**	**-22.2**	108.7	209.8
Other comprehensive income	—	—	—	—
Total comprehensive income	**-78.1**	**-22.2**	108.7	209.8
Attributable to:				
Shareholders of the Parent Company	-78.1	-22.2	108.7	209.8
	-78.1	**-22.2**	108.7	209.8

Parent Company Balance Sheet

Expressed in MSEK	**31 December 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	17.5	16.7
Cash and cash equivalents	0.4	1.8
Total current assets	**17.9**	18.5
TOTAL ASSETS	**7,889.9**	7,890.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,782.4	7,860.5
Non-current liabilities		
Provisions	0.4	0.3
Payables to group companies	100.7	–
Total non-current liabilities	**101.1**	0.3
Current liabilities		
Current liabilities	6.4	16.2
Payables to group companies	–	13.5
Total current liabilities	**6.4**	29.7
Total liabilities	**107.5**	30.0
TOTAL EQUITY AND LIABILITIES	**7,889.9**	7,890.5
Pledged assets	3,569.7	8,717.8

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2015– 31 Dec 2015 12 months**	**1 Oct 2015– 31 Dec 2015 3 months**	1 Jan 2014 – 31 Dec 2014 12 months	1 Oct 2014 – 31 Dec 2014 3 months
Cash flow from operations				
Net result	-78.1	-22.2	108.7	209.8
Adjustment for non-cash related items	0.3	0.2	-36.7	-36.5
Changes in working capital	-23.8	-79.9	11.0	-173.8
Total cash flow from operations	**-101.6**	**-101.9**	83.0	-0.5
Cash flow from investments				
Change in other fixed assets	–	–	-0.1	–
Total Cash flow from investments	–	–	-0.1	–
Cash flow from financing				
Change in long-term liabilities	100.4	100.4	-21.7	–
Purchase of own shares	–	–	-62.2	–
Total cash flow from financing	**100.4**	**100.4**	-83.9	–
Change in cash and cash equivalents	-1.2	-1.5	-1.0	-0.5
Cash and cash equivalents at the beginning of the period	1.8	1.9	2.6	2.3
Currency exchange difference in cash and cash equivalents	-0.2	–	0.2	–
Cash and cash equivalents at the end of the period	**0.4**	**0.4**	1.8	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	**–**	**–**	**–**	**108.7**	**108.7**	**108.7**
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 31 December 2014	**3.2**	**861.3**	**2,295.3**	**4,700.7**	**6,996.0**	**7,860.5**
Total comprehensive income	**–**	**–**	**–**	**-78.1**	**-78.1**	**-78.1**
Balance at 31 December 2015	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**6,917.9**	**7,782.4**

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 2015–31 Dec 2015 12 months**	**1 Oct 2015–31 Dec 2015 3 months**	1 Jan 2014–31 Dec 2014 12 months	1 Oct 2014–31 Dec 2014 3 months
Revenue	569.3	136.0	785.2	135.2
EBITDA	384.7	93.6	671.3	164.4
Net result	-866.3	-493.7	-431.9	-437.0
Operating cash flow	699.6	175.4	1,138.5	334.5
Data per share (USD)				
Shareholders' equity per share	-1.61	-1.61	1.40	1.40
Operating cash flow per share	2.26	0.57	3.68	1.08
Cash flow from operations per share	1.01	0.87	1.96	-0.12
Earnings per share	-2.79	-1.59	-1.38	-1.41
Earnings per share fully diluted	-2.78	-1.59	-1.38	-1.41
EBITDA per share	1.24	0.30	2.17	0.53
Dividend per share	–	–	–	–
Number of shares issued at period end	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
Weighted average number of shares for the period	309,070,330	309,070,330	309,170,986	309,170,986
Weighted average number of shares for the period fully diluted	310,019,890	310,019,890	309,475,038	309,475,038
Share price				
Quoted price at period end (SEK)	122.60	122.60	112.40	112.40
Key ratios				
Return on equity (%) [1]	–	–	-50	-50
Return on capital employed (%)	-26	-22	-11	-19
Net debt/equity ratio (%) [1]	–	–	605	605
Equity ratio (%)	-10	-10	9	9
Share of risk capital (%)	1	1	28	28
Interest coverage ratio	-11	-31	-13	-54
Operating cash flow/interest ratio	9	7	49	33
Yield	n/a	n/a	n/a	n/a

[1] As the equity in 2015 is negative, these ratios have not been calculated.

Key Ratio Definitions

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

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

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

Operating cash flow per share: 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.

Stockholm, 3 February 2016

Ian H. Lundin Chairman	Peggy Bruzelius	C. Ashley Heppenstall
Lukas H. Lundin	William A. Rand	Grace Reksten Skaugen
Magnus Unger	Cecilia Vieweg	

Alex Schneiter
President and CEO

The Company will publish the following reports:

- The three month report (January — March 2016) will be published on 11 May 2016.
- The six month report (January — June 2016) will be published on 3 August 2016.
- The nine month report (January — September 2016) will be published on 2 November 2016.

The 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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