Lundin Petroleum

Q3

Report for the
NINE MONTHS
ended 30 September 2019

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

- Production above mid-point guidance for the nine months at 79.2 Mboepd and Q3 at 82.7 Mboepd
- Production ramp up from Johan Sverdrup Phase 1 above 200 Mboepd gross as at end of October 2019, following first oil on 5 October 2019, ahead of schedule and under budget
- 2019 production guidance raised to 90 to 95 Mboepd from 75 to 95 Mboepd, following early start up from Johan Sverdrup and continued outperformance from Edvard Grieg
- Strong financial performance for the reporting period and third quarter
- Completion of 2.6 percent sale of Johan Sverdrup and 16 percent shares redemption with Equinor in August 2019
- Plan to fully electrify Edvard Grieg as part of the Utsira High Area power grid finalised, increasing uptime efficiency further and continuing our emissions trajectory to below 1kg CO_2 per boe from the Johan Sverdrup and Edvard Grieg fields

Financial summary

	1 Jan 2019-30 Sep 2019 9 months	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Production in Mboepd	**79.2**	**82.7**	80.8	78.2	81.1
Revenue and other income in MUSD	**2,199.0**	**1,215.0**	1,988.5	604.6	2,640.7
Operating cash flow in MUSD[1]	**1,158.9**	**380.0**	1,412.8	434.4	1,864.1
EBITDA in MUSD[1]	**1,222.9**	**411.3**	1,451.8	476.8	1,932.5
Free cash flow in MUSD	**1,117.9**	**950.5**	489.7	228.7	663.0
Net result in MUSD	**669.6**	**519.9**	323.9	56.7	225.7
Adjusted net result in MUSD	**173.8**	**45.4**	220.1	75.1	295.3
Earnings/share in USD	**2.05**	**1.72**	0.96	0.17	0.67
Adjusted earnings/share in USD	**0.53**	**0.15**	0.65	0.22	0.87
Net debt in MUSD	**4,054.9**	**4,054.9**	3,569.9	3,569.9	3,398.2

[1] Excludes the reported after tax accounting gain of MUSD 756.7 on the divestment of a 2.6 percent working interest in the Johan Sverdrup project.

Comment from Alex Schneiter, President and CEO of Lundin Petroleum:

"I am pleased to announce another very good quarter of operational and financial performance. The Company's production currently stands at over 120 Mboepd and as a result of continued outperformance from Edvard Grieg and an earlier startup and quicker ramp up of the pre-drilled wells at Johan Sverdrup, we are raising the production guidance for the year to between 90 and 95 Mboepd.

"A stand out moment for us was first oil from the world class Johan Sverdrup Phase 1 project, which was achieved on 5 October 2019, ahead of schedule and significantly below budget. Since then production has been ramping up ahead of expectations, as the eight pre-drilled wells are progressively commissioned and as at the end of October 2019, the field was producing above 200 Mboepd gross from five wells. It is now anticipated that all of the eight pre-drilled wells will be on production during November 2019. We will then drill the remaining two to four new wells required to achieve Phase 1 plateau production of 440 Mbopd, which is expected by summer 2020.

"Our other production assets continue to perform well, with operating costs at industry leading levels and in line with our guidance for the year. Edvard Grieg continues to exceed expectations with uptime and production above forecast. With the approval of the new infill drilling programme in 2020, we are now anticipating the gross ultimate proved plus probable reserves will be over 300 MMboe as compared to the original PDO of 186 MMboe. This is a fantastic indictment to the quality of this field.

"As an important development we've now sanctioned the full electrification of the Edvard Grieg facility as part of the Utsira High Area power grid, which is being developed together with Johan Sverdrup Phase 2. This project will result in a significant reduction in CO_2 emissions from the field, taking Edvard Grieg Area CO_2 emissions below 1 kg per barrel. This will mean that our two key assets, Edvard Grieg and Johan Sverdrup, will have emissions of below 1kg CO_2 per boe, about twenty times lower than the world average and one of the lowest for any offshore operator. This is in line with the Board endorsed Sustainable Energy Strategy, which will provide the Company with the roadmap to continue to be one of the most efficient offshore oil and gas producers in terms of low emissions per barrel produced, as well as increased operating efficiency. Our aim is to continue to further reduce our carbon footprint and increase overall efficiency through new investments and innovative approaches. In this regard, the investment in a hydro power project in Norway to offset the Company's net non-renewable electricity usage for power from shore, is in line with this strategy.

"Looking ahead to the rest of the year; we remain in the intensive ramp up period at Johan Sverdrup and development operations at Solveig and Phase 2 of Johan Sverdrup are progressing on schedule. It will also be another busy period for us with the exploration drill bit, focussed north of the Utsira High and in the North Norwegian Sea, targeting net unrisked resources of 130 MMboe for the remainder of the year and a significant exploration drilling programme is taking shape for 2020 as we continue to drive our organic growth strategy. This is the 17th quarter of production delivery on or above expectations and I look forward to updating shareholders in January 2020 on the full year 2019 progress."

Lundin Petroleum is one of Europe's leading independent oil and gas exploration and production companies with operations focused on Norway and listed on NASDAQ Stockholm (ticker LUPE). Read more about Lundin Petroleum's business and operations at www.lundin-petroleum.com

For definitions and abbreviations, see pages 31 and 32.

OPERATIONAL REVIEW

All the reported numbers and updates in the operational review relate to the nine month period ending 30 September 2019 (reporting period) unless otherwise specified.

Guidance Update

On 5 October 2019, the Company announced the start of production from Phase 1 of the Johan Sverdrup field. Upon this, the adjustments to guidance inclusive of other operational updates are as follow:

2019 guidance	Updated	Previous
Production	90 to 95 Mboepd	75 to 95 Mboepd
Operating Cost	USD 4.25 per boe	USD 4.25 per boe
Development Capital Expenditure	MUSD 730	MUSD 785
Exploration and Appraisal Expenditure	MUSD 325	MUSD 325

Norway

Production

Production was 79.2 thousand barrels of oil equivalent per day (Mboepd), which was 4 percent above mid-point of the production guidance for the reporting period, and 82.7 Mboepd for the third quarter. This result is due to continued good performance at both Edvard Grieg and the Alvheim area. Lundin Petroleum is increasing its full year production guidance to between 90 and 95 Mboepd from the original guidance range of between 75 and 95 Mboepd, reflecting both the impact of early first oil from the Johan Sverdrup field which occurred on 5 October 2019 and the strong performance from the Company's other producing assets during the reporting period.

Operating cost, including netting off tariff income, was USD 4.31 per barrel, which is in line with guidance. Full year operating cost guidance remains USD 4.25 per barrel.

Detail of production performance from Johan Sverdrup Phase 1 following first oil on 5 October 2019, is included in the development section below.

Production in Mboepd	**1 Jan 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Norway					
Crude oil	70.1	72.9	71.4	68.9	71.9
Gas	9.1	9.8	9.4	9.3	9.2
Total production	**79.2**	**82.7**	80.8	78.2	81.1

Production in Mboepd	WI[1]	**1 Jan 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Edvard Grieg	65%	63.6	66.6	63.0	61.6	63.6
Ivar Aasen	1.385%	0.8	0.8	0.9	0.9	0.9
Alvheim	15%	9.3	8.6	9.0	9.0	9.3
Volund	35%	4.8	5.6	7.0	5.9	6.5
Bøyla	15%	0.7	1.1	0.8	0.8	0.7
Gaupe	40%	–	–	0.1	0.0	0.1
		79.2	**82.7**	80.8	78.2	81.1

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

Production from the Edvard Grieg field was 5 percent above forecast, supported by production efficiency above guidance at 98 percent. Reservoir performance continues to exceed expectations; with limited water production and total well potential significantly higher than available facilities capacity. An infill drilling programme planned to commence in 2020 has been sanctioned, targeting increased resources of 18 MMboe gross, based on a three well programme, which is anticipated to take the gross field ultimate proved plus probable reserves to over 300 MMboe. The Rowan Viking jack-up rig, used to drill all the existing development wells at the Edvard Grieg field, has been contracted for the infill programme. Based on the performance at Edvard Grieg and the addition of the Solveig and Rolvsnes tie-back projects, the forecast plateau production period through the Edvard Grieg facilities has been extended to around the end of 2022. During the second quarter 2019, a dual-branch exploration well made oil discoveries at Jorvik and Tellus East on the eastern edge of the Edvard Grieg field. Both areas can be accessed with wells drilled from the platform, with Jorvik the target of one of the planned wells in the first infill campaign. Operating cost for the Edvard Grieg field, including netting off tariff income, was USD 4.14 per barrel.

The plan to fully electrify the Edvard Grieg platform has been finalised in conjunction with the Utsira High Area power grid that is being developed together with the Johan Sverdrup Phase 2 project. The Edvard Grieg electrification project, which will become operational in 2022, involves the retirement of the existing gas turbine power generation system on the platform, installation of electric boilers to provide process heat and installation of a power cable from Johan Sverdrup to Edvard Grieg. The project will result in a significant reduction in CO_2 emissions from the Edvard Grieg Area of approximately 3.6 million tonnes from 2022 to end of field life, taking CO_2 emissions for the area to below 1 kg per barrel, about twenty times lower than the world average. Additionally, the project will reduce operating costs, reduce carbon taxes and increase operating efficiency, which is partially offset by electricity power purchases from the grid.

Production from the Ivar Aasen field was slightly below forecast. Two infill wells have been drilled during the year, which are both producing in line with expectations.

Production from the Alvheim area, consisting of the Alvheim, Volund and Bøyla fields, was in line with forecast. Production efficiency for the Alvheim FPSO was ahead of expectations at 97 percent. Two production wells came on stream during the reporting period, a sidetrack infill well at the Volund field and the two-branch Frosk test producer (which is produced through the Bøyla facilities), both wells are producing in line with expectations. The Frosk well also included the drilling of two pilot holes, one of which tested the Froskelår North East prospect making a small oil discovery. In the third quarter 2019, a three-branch pilot well aimed at de-risking infill well opportunities in the Alvheim field was drilled, overall results were above expectations and will lead to an infill well to be drilled in 2020. Operating cost for the Alvheim area was USD 6.23 per barrel.

Development

Field	WI	Operator	Estimated gross reserves	Production start	Expected gross plateau production
Johan Sverdrup	20%	Equinor	2.2 — 3.2 Bn boe	October 2019	660 Mbopd
Solveig Phase 1	65%	Lundin Norway	57 MMboe	Q1 2021	30 Mboepd
Rolvsnes EWT	80%	Lundin Norway	-	Q2 2021	3 Mboepd

The development expenditure guidance for 2019 is being reduced to MUSD 730 as a result of costs being phased into 2020 for the Company's key projects and costs savings from a weaker NOK.

Johan Sverdrup

Phase 1 of the Johan Sverdrup project commenced production on 5 October 2019, which is at the front of the guidance range for first oil. Phase 1 of the project has been developed as a field centre of four platforms - drilling, processing, living quarters and riser platform. Production is ramping up quickly ahead of expectations as the eight pre-drilled wells are progressively commissioned and at the end of October 2019 the field was producing above 200 Mboepd gross from five wells, with the remaining three pre-drilled wells to come on stream during November 2019. Also the twelve pre-drilled water injection wells are progressively being commissioned to provide pressure support to the reservoir, with water injection currently ongoing into seven wells. The gross production capacity of Phase 1 is estimated at 440 Mbopd, expected to be achieved by summer 2020 and will require two to four new wells to be drilled, with the first of these expected to come on stream in early 2020. The field is being operated with power supplied from shore and will be one of the lowest CO_2 emitting fields in the world, with CO_2 emissions of below 1 kg per barrel, about 20 times less than the world average. Post Phase 1 plateau, operating costs will be below USD 2 per barrel.

Johan Sverdrup Phase 1 has been delivered below the original capital budget with a current estimate of gross NOK 83 billion (nominal), representing a saving to date of approximately NOK 40 billion compared to the Phase 1 PDO estimate of gross NOK 123 billion (nominal). Approximately 10 percent of the current Phase 1 capital estimate remains to be spent on final completion of the production facilities and fifteen new Phase 1 platform development wells to be drilled over the period from fourth quarter 2019 to 2023.

The Phase 2 PDO was submitted to the Norwegian Ministry of Petroleum and Energy in August 2018 and was approved in May 2019. Phase 2 involves a second processing platform bridge linked to the Phase 1 field centre, subsea facilities to allow for tie-in of additional wells to access the Avaldsnes, Kvitsøy and Geitungen satellite areas of the field and implementation of full field water alternating gas injection (WAG) for enhanced recovery. 28 wells are planned to be drilled in connection with the Phase 2 development. Phase 2 first oil is scheduled in the fourth quarter 2022, which will take the gross plateau production capacity to 660 Mbopd. Full field breakeven oil price, including past investments, is estimated at below USD 20 per barrel.

The Phase 2 capital expenditure is estimated at gross NOK 41 billion (nominal), which is unchanged from the Phase 2 PDO estimate and over a 50 percent saving from the original estimate in the Phase 1 PDO. The major topsides, jacket and Subsea Production System contracts, have been awarded. Construction has commenced on the second processing platform topsides and as well as the new modules to be installed on the existing Riser Platform. Phase 2 of the project is progressing to plan and is approximately 15 percent complete.

Greater Edvard Grieg Area Tie-Back Projects

The PDO for the Solveig Phase 1 project was approved by the Norwegian Ministry of Petroleum and Energy in June 2019. Solveig is the first Edvard Grieg subsea tie-back development and will contribute to keeping the Edvard Grieg platform filled to capacity for an extended time period. Phase 1 will be developed with three oil production wells and two water injection wells and will achieve gross peak production of 30 Mboepd, with first oil scheduled in the first quarter 2021.

Solveig Phase 1 gross proved plus probable reserves are estimated at 57 MMboe. The capital cost of the development is estimated at MUSD 810 gross, with a breakeven oil price of below USD 30 per barrel. The potential for further phases of development, which will capture the upside potential in the discovered resources, will be de-risked by production performance from Phase 1.

The production application for the Rolvsnes Extended Well Test (EWT) was approved by the Norwegian Ministry of Petroleum and Energy in July 2019. The Rolvsnes EWT project will be conducted through a 3 km subsea tie-back of the existing Rolvsnes horizontal well to the Edvard Grieg platform. The project is being implemented together with the Solveig project to take advantage of contracting and implementation synergies, with first oil scheduled in the second quarter 2021.

Both Edvard Grieg Area tie-back projects are progressing according to plan, with the Solveig Phase 1 project now over 10 percent complete and the Rolvsnes EWT project over 15 percent complete. All of the key contracts have been awarded and modifications at the Edvard Grieg platform commenced in May 2019.

Appraisal

2019 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL167	Equinor	20%	Lille Prinsen	May 2019	Completed July 2019
PL203	AkerBP	15%	Alvheim Infill Pilots	August 2019	Completed September 2019

In July 2019, an appraisal well was completed on the Lille Prinsen oil discovery made in 2018 in PL167 located in the Utsira High area of the North Sea. The original discovery, Lille Prinsen Main, is estimated to contain gross resources of between 15 and 35 MMboe. The appraisal well was drilled 1 km west of the discovery well in the downdip Outer Wedge area, making an oil discovery, with the resource estimate pending full assessment of the well results. Other segments of Lille Prinsen will be evaluated for further delineation.

Following the extended well test on the Alta discovery in 2018 and the acquisition of a new 3D seismic (Topseis), technical work is ongoing to determine the forward appraisal strategy for Alta and the nearby Gohta discovery.

Exploration

2019 exploration well programme

Licence	Operator	WI	Well	Spud Date	Result
PL857	Equinor	20%	Gjøkåsen Shallow	December 2018	Dry
PL767	Lundin Norway	50%	Pointer/Setter	January 2019	Dry
PL869	AkerBP	20%	Froskelår Main	January 2019	Oil & Gas Discovery
PL857	Equinor	20%	Gjøkåsen Deep	February 2019	Dry
PL338	Lundin Norway	65%	Jorvik/Tellus East	March 2019	Two Oil Discoveries
PL869	AkerBP	20%	Froskelår North East	March 2019	Oil Discovery
PL539	MOL	20%	Vinstra/Otta	April 2019	Dry
PL916	AkerBP	20%	JK	April 2019	Dry
PL859	Equinor	15%	Korpfjell Deep	June 2019	Dry
PL758	Capricorn	20%	Lynghaug	June 2019	Dry
PL869	AkerBP	20%	Rumpetroll	June 2019	Dry
PL815	Lundin Norway	60%	Goddo	July 2019	Oil Discovery
PL921	Equinor	15%	Gladsheim	September 2019	Dry
PL820S[1]	MOL	30%	Evra/Iving	Fourth Quarter 2019	
PL896[1]	Wintershall DEA	20%	Toutatis	Fourth Quarter 2019	
PL917	ConocoPhillips	20%	Enniberg	Fourth Quarter 2019	

[1] Lundin's working interest will increase to 40% in PL820S, and to 30% in PL896 on closing of the Wintershall DEA transaction

The 2019 exploration drilling programme has been reduced to 16 wells with the slippage of the PL917 Hasselbaink well to early 2020. Thirteen exploration wells have been completed so far in 2019, yielding five oil discoveries and adding net resources of between 10 and 50 MMboe. The remaining three exploration wells to be drilled in 2019 are targeting net unrisked resources of approximately 130 MMboe. The exploration and appraisal expenditure guidance for 2019 is being maintained at MUSD 325.

In February 2019, the Gjøkåsen Shallow prospect in PL857 and the Pointer/Setter dual target prospect in PL767, both located in the southern Barents Sea, were drilled and both wells were dry.

In March 2019, the Froskelår Main prospect in PL869 in the Alvheim area proved an oil and gas discovery. The discovery is estimated by the operator to contain gross resources of between 60 and 130 MMboe with part of the discovery potentially extending into the UK. Froskelår Main will be evaluated as part of a potential joint development with the Frosk discovery.

In April 2019, the Gjøkåsen Deep prospect in PL857 in the southeastern Barents Sea, the Vinstra/Otta prospect in PL539 located in the Mandal High area of the North Sea and the JK prospect in PL916 located in the north of the Utsira High area of the North Sea, were all drilled and all three wells were dry.

In June 2019, the Korpfjell Deep prospect in PL859 in the southeastern Barents Sea was drilled and was dry.

In June 2019, the Jorvik and Tellus East prospects on the eastern edge of the Edvard Grieg field in PL338 proved two oil discoveries. At Jorvik, the well encountered oil in 30 metres of conglomerate reservoir of Triassic age with a thin, high quality sandstone above. This combination of conglomerate and sandstone reservoir types are also found on the southern and eastern part of Edvard Grieg. At Tellus East, the well encountered a gross oil column of 60 metres in porous, weathered basement reservoir. The combined gross resources of Jorvik and Tellus East are estimated to be between 4 and 37 MMboe and both can be developed with wells from the Edvard Grieg platform.

In June 2019, the Froskelår North East prospect was drilled as part of the Frosk test producer and proved an oil discovery. The discovery is estimated by the operator to contain gross resources of between 2 and 10 MMboe and is potentially commercial as part of a Frosk/Froskelår development.

In July 2019, the Lynghaug prospect in PL758 in the Norwegian Sea, and the Rumpetroll prospect in PL869 in the Alvheim area, were drilled and both wells were dry.

In August 2019, the Goddo prospect in PL815 located on the Utsira High was drilled and proved an oil discovery. The main objective of the well was to prove oil in porous basement similar to what is found in the Rolvsnes discovery located to the northwest. The Goddo well encountered weathered and fractured basement with an estimated gross oil column of 20 metres, with reservoir of similar characteristics as found in Rolvsnes, but the two discoveries are not connected. Gross resources at Goddo are estimated to be between 1 and 10 MMboe, with further upside potential in the larger Goddo area and surrounding prospective basement. The results from the Rolvsnes EWT will provide important reservoir performance data in relation to the commercialisation of the wider basement opportunity on the Utsira High.

In October 2019, the Gladsheim prospect in PL921 in the Northern North Sea was drilled and was dry.

Sustainable Energy Plan
With Johan Sverdrup fully electrified from shore and Edvard Grieg being fully electrified as part of the recently announced Utsira High Area power solution; Lundin Petroleum will be using around 500 GWh per annum net of electricity from 2022 from Nord Pool, the Nordic countries' electricity transmission system, the majority of which is generated from renewable energy sources. However, in order to offset the non-renewable element (estimated at about a third of the total electricity usage) of the power to Johan Sverdrup and subsequently Edvard Grieg, direct and profitable investment in renewable energy will be undertaken in order to continue to reduce the Company's carbon impact.

The Company signed an agreement with Sognekraft AS to acquire a 50 percent non-operated interest in the Leikanger Hydropower project, in midwest Norway. Leikanger will produce around 208 GWh per annum gross, once it is fully operational in 2021, from a river run off hydropower generation scheme and will more than offset the non-renewable energy required for our net share of Johan Sverdrup Phase 1 power consumption. The investment to Lundin Petroleum is approximately MUSD 60 over the three year period 2019 to 2021 and the project will be Free Cash Flow positive from 2022. The project will also provide a natural hedge to the electricity price fluctuation; Johan Sverdrup electricity share of the operating costs accounts for approximately 15 percent of the total operating costs. The completion of the transaction remains subject to customary closing conditions, with closing expected to occur in early 2020.

It is the intention of Lundin Petroleum to continue to seek opportunities to offset and replace its net electricity consumption being used to power the Johan Sverdrup and subsequently Edvard Grieg facilities.

Decommissioning
Preparation of the decommissioning plan for the Brynhild field is ongoing with operations anticipated to be conducted during 2020/2021. The Rowan Viking jack-up drilling rig has been secured to plug and abandon the four Brynhild wells.

The Gaupe field ceased production during the fourth quarter of 2018 and preparation of the decommissioning plan for the field is also ongoing.

Licence awards and transactions
In January 2019, Lundin Petroleum was awarded 15 licences in the 2018 APA licensing round, of which nine are as operator.

In January 2019, Lundin Petroleum entered into a sales and purchase agreement involving the acquisition of Lime Petroleum's 30 percent working interest in each of PL338C and PL338E and 20 percent working interest in PL815, which contain the Rolvsnes and Goddo oil discoveries. The transaction increased the Company's working interest in each of PL338C and PL338E to 80 percent and in PL815 to 60 percent. The transaction involved a cash consideration payable to Lime Petroleum and was completed in May 2019, with economic effect from 1 January 2019.

In June 2019, Lundin Petroleum entered into a sales and purchase agreement involving the acquisition of a 10 percent working interest in each of PL896 and PL820S from Wintershall DEA. The transaction will increase the Company's working interest to 40 percent in PL820S which contains the Evra/Iving prospects located in the North Sea and to 30 percent in PL896 which contains the Toutatis prospect located in the Norwegian Sea. The transaction is subject to customary government approvals and is expected to complete in the fourth quarter of 2019.

In July 2019, as part of transaction to redeem 16 percent of the outstanding Lundin Petroleum shares held by Equinor, the Company further entered into an asset transfer agreement to sell 2.6 percentage points of the Johan Sverdrup development project to Equinor for a cash consideration of MUSD 962 with an effective date of 1 January 2019, which includes a MUSD 52 contingent payment on future reserve attainment. The asset transaction was completed on 30 August 2019.

In September 2019, Lundin Petroleum applied for licences in the 2019 APA licensing round where awards are anticipated in early 2020.

Currently the Company holds 79 licences in Norway, which is an increase of approximately 60 percent from the beginning of 2018.

Russia
Lundin Petroleum has previously written down the entire contingent resources and book value for the Morskaya oil discovery in Russia, as it was deemed unlikely that the discovery could commercially be developed in the foreseeable future. Having reviewed potential options, the partnership concluded that it is not possible for the partnership to create value from the asset and consequently the Morskaya licence has been relinquished and the local operating company, PetroResurs, has been liquidated.

Health, Safety and Environment
During the reporting period, no lost time incidents and one medical treatment incident occurred, resulting in a Lost Time Incident Rate of 0.0 per million hours worked and a Total Recordable Incident Rate of 0.8 per million hours worked. There were no material safety or environmental incidents. The trend of industry leading low carbon operations continued at the Edvard Grieg field with a carbon intensity of 4.9 kg CO_2 per boe during the reporting period.

FINANCIAL REVIEW

Result

The operating profit for the reporting period amounted to MUSD 1,588.2 (MUSD 1,102,2) and included a MUSD 756.7 after tax accounting gain on the sale of 2.6 percent of Johan Sverdrup. The operating profit for the reporting excluding this accounting gain amounted to MUSD 831.5 with the decrease compared to the comparative period driven by higher expensed exploration costs during the reporting period, lower oil prices and slightly lower sold volumes, somewhat offset by lower depletion costs.

The net result for the reporting period amounted to MUSD 669.6 (MUSD 323.9) representing earnings per share of USD 2.05 (USD 0.96). Net result was impacted by a MUSD 756.7 after tax accounting gain on the sale of 2.6 percent of Johan Sverdrup during the reporting period, a foreign currency exchange loss of MUSD 237.7 (MUSD 1.2) and an accounting gain of MUSD 183.7 pre tax in the comparative period as a result of the re-negotiated improved borrowing terms for the reserve-based lending facility. Management has introduced reporting of an adjusted net result metric, with the objective of better reflecting the net result generated by the Company's operational performance for the reporting period. Adjusted net result separates out the effects of accounting gains/losses from asset sales, loan modification gains, foreign currency exchange results, impairment charges and the tax impacts from these items. Adjusted net result for the reporting period amounted to MUSD 173.8 (MUSD 220.1) representing adjusted earnings per share of USD 0.53 (USD 0.65). The decrease compared to the comparative period was mainly driven by a lower adjusted operating profit, somewhat offset by lower adjusted finance costs.

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 1,222.9 (MUSD 1,451.8) representing EBITDA per share of USD 3.75 (USD 4.29) with the decrease compared to the comparative period mainly relating to a lower realized price per boe and slightly lower sales volumes. Operating cash flow for the reporting period amounted to MUSD 1,158.9 (MUSD 1,412.8) representing operating cash flow per share of USD 3.55 (USD 4.17) with the decrease compared to the comparative period further impacted by a higher current tax charge. Free cash flow for the reporting period amounted to MUSD 1,117.9 (MUSD 489.7) representing free cash flow per share of USD 3.42 (USD 1.45) with the increase compared to the comparative period impacted by the cash inflow from the sale of 2.6 percent of Johan Sverdrup of MUSD 959.0 which includes received interest and pro and contra funding settlement from effective date to completion date as well as working capital balances and incurred expenses.

Changes in the Group

In January 2019, Lundin Petroleum entered into a sales and purchase agreement for the acquisition of Lime Petroleum's 30 percent working interest in each of PL338C and PL338E and 20 percent working interest in PL815, which contain the Rolvsnes oil discovery and Goddo prospect. The transaction increased the Company's working interest in each of PL338C and PL338E to 80 percent and in PL815 to 60 percent. The transaction involved a cash consideration payable to Lime Petroleum of MUSD 43.0 and was completed in May 2019, with economic effect from 1 January 2019.

In July 2019, Lundin Petroleum entered into a sales and purchase agreement for the sale of a 2.6 percent working interest in the Johan Sverdrup development project to Equinor. The transaction decreased the Company's working interest in the Johan Sverdrup development project to 20 percent. The transaction involved a cash consideration payable by Equinor of MUSD 962.0, which includes a nominal MUSD 52.0 contingent payment on future reserve reclassifications. The transaction was completed in August 2019, with economic effect from 1 January 2019. The transaction was accounted for at closing resulting in a net after tax accounting gain of MUSD 756.7 arising from the difference between the consideration received and the book value of the associated assets being divested. The accounting gain is reported as gain from sale of assets as detailed in the following table. The gain from the sale is presented on an after tax basis as the consideration is determined net after tax based on the Norwegian Petroleum Tax regulations.

Expressed in MUSD	
Assets	
Oil and gas properties	343.7
Total assets divested	**343.7**
Liabilities	
Site restoration provision	16.2
Deferred tax liabilities	108.9
Working capital	4.0
Total liabilities divested	**129.1**
Net assets divested	**214.6**
Consideration[1]	974.0
Incurred expenses	-2.7
Net after tax accounting gain	**756.7**

[1] Includes fair value of the contingent consideration on future reserve reclassifications, received interest and pro and contra funding settlement from effective date to completion date as well as working capital balances

Revenue and other income

Revenue and other income for the reporting period amounted to MUSD 2,199.0 (MUSD 1,988.5) and was comprised of net sales of oil and gas, gain from sale of 2.6 percent of Johan Sverdrup and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 1,418.3 (MUSD 1,963.3). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 61.14 (USD 68.92) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 64.59 (USD 72.13) per barrel.

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

Sales from own production Average price per boe expressed in USD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Crude oil sales					
– Quantity in Mboe	19,039.0	7,028.0	19,597.2	5,881.4	26,834.7
– *Average price per bbl*	*65.29*	*61.44*	*71.28*	*74.09*	*69.97*
Gas and NGL sales					
– Quantity in Mboe	2,780.2	788.0	2,805.6	1,233.9	3,682.0
– *Average price per boe*	*32.74*	*23.87*	*52.50*	*55.34*	*52.74*
Total sales					
– Quantity in Mboe	**21,819.2**	**7,816.0**	22,402.8	7,115.3	30,516.7
– Average price per boe	***61.14***	***57.65***	*68.92*	*70.84*	*67.89*

The table above excludes crude oil revenue from third party activities.

Net sales of crude oil from third party activities for the reporting period amounted to MUSD 84.3 (MUSD 419.1) and consisted of Grane Blend crude oil purchased from outside the Group by Lundin Petroleum Marketing SA and sold to the market.

Sales of oil and gas are recognised when the risk of ownership is transferred to the purchaser.

Gain from sale of assets amounted to MUSD 756.7 (MUSD –) and related to the sale of 2.6 percent of Johan Sverdrup as specified on page 7.

Other income for the reporting period amounted to MUSD 24.0 (MUSD 25.2) and mainly included tariff income of MUSD 19.5 (MUSD 22.7) which is due to net income from Ivar Aasen tariffs paid to Edvard Grieg.

Production costs

Production costs including under/over lift movements and inventory movements for the reporting period amounted to MUSD 118.6 (MUSD 103.8) and are detailed in Note 2. The total production cost per barrel of oil equivalent produced is detailed in the table below:

Production costs	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Cost of operations					
– In MUSD	81.9	25.5	74.0	26.6	102.5
– In USD per boe	*3.79*	*3.35*	*3.35*	*3.70*	*3.46*
Tariff and transportation expenses					
– In MUSD	30.7	10.9	25.8	8.6	35.2
– In USD per boe	*1.42*	*1.44*	*1.17*	*1.19*	*1.19*
Operating costs					
– In MUSD	**112.6**	**36.4**	99.8	35.2	137.7
–In USD per boe[1]	***5.21***	***4.79***	*4.52*	*4.89*	*4.65*
Change in under/over lift position					
– In MUSD	2.6	4.2	-2.0	-5.1	7.0
– In USD per boe	*0.12*	*0.54*	*-0.09*	*-0.71*	*0.24*
Change in inventory position					
– In MUSD	0.3	0.0	0.6	0.0	0.6
– In USD per boe	*0.02*	*0.00*	*0.03*	*0.00*	*0.02*
Other					
– In MUSD	3.1	1.0	5.4	1.7	7.1
– In USD per boe	*0.14*	*0.13*	*0.24*	*0.24*	*0.24*
Production costs					
– In MUSD	**118.6**	**41.6**	103.8	31.8	152.4
–In USD per boe	***5.49***	***5.46***	*4.70*	*4.42*	*5.15*

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

[1] The numbers in this table are excluding tariff income netting. Lundin Petroleum's operating cost for the reporting period of USD 5.21 (USD 4.52) per barrel is reduced to USD 4.31 (USD 3.49) when tariff income is netted off. The operating cost for the third quarter of USD 4.79 (USD 4.89) per barrel is reduced to USD 3.97 (USD 3.88) when tariff income is netted off.

The total cost of operations for the reporting period amounted to MUSD 81.9 (MUSD 74.0) and the total cost of operations excluding operational projects amounted to MUSD 74.4 (MUSD 67.5). The increase compared to the comparative period included the reversal in the comparative period of an accrual as a result of the termination of production from the Brynhild field of MUSD 5.5.

The cost of operations per barrel for the reporting period amounted to USD 3.79 (USD 3.35) including operational projects and USD 3.44 (USD 3.06) excluding operational projects.

Tariff and transportation expenses for the reporting period amounted to MUSD 30.7 (MUSD 25.8) or USD 1.42 (USD 1.17) per barrel. The increase compared to the comparative period is driven by higher pipeline tariff rates in combination with freight costs for crude oil sales in relation to some cargoes being sold on a CFR basis during the period.

Sales quantities in a period can differ from production quantities as a result of permanent and timing differences. Timing differences can arise due to under/over lift of entitlement, inventory, storage and pipeline balances effects. The change in under/over lift position is valued at production cost including depletion cost, and amounted to MUSD 2.6 (credit of MUSD 2.0) in the reporting period due to the timing of the cargo liftings compared to production. Sales quantities and production quantities are detailed in the table below:

Change in over/underlift position In Mboepd	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Production volumes	**79.2**	**82.7**	80.8	78.2	81.1
Sales volumes from own production	**-79.9**	**-85.0**	82.1	77.3	83.6
Change in underlift / overlift position	**-0.7**	**-2.3**	-1.3	0.9	-2.5

Other costs for the reporting period amounted to MUSD 3.1 (MUSD 5.4) and related to the business interruption insurance.

Depletion and decommissioning costs

Depletion and decommissioning costs for the reporting period amounted to MUSD 301.6 (MUSD 341.5) at an average rate of USD 13.95 (USD 15.48) per barrel and are detailed in Note 3. The lower depletion costs for the reporting period compared to the comparative period is due to lower production volumes in combination with a lower depletion rate per barrel in USD terms as the depletion rate per barrel is calculated in Norwegian Kroner and with the Norwegian Kroner having weakened the USD depletion rate has been reduced.

Exploration costs

Exploration costs expensed in the income statement for the reporting period amounted to MUSD 84.7 (MUSD 6.1) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration and appraisal 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.

Purchase of crude oil from third parties

Purchase of crude oil from third parties for the reporting period amounted to MUSD 84.3 (MUSD 417.2) and related to Grane Blend crude oil purchased from outside the Group.

General, administrative and depreciation expenses

The general administrative and depreciation expenses for the reporting period amounted to MUSD 21.6 (MUSD 17.7) which included a charge of MUSD 3.4 (MUSD 3.4) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section on page 13. Fixed asset depreciation expenses for the reporting period amounted to MUSD 5.1 (MUSD 2.0) with the increase compared to the comparative period mainly caused by the implementation of IFRS 16 with effective date 1 January 2019 based on which depreciation expenses relating to right of use assets are included in the reporting period.

Finance income

Finance income for the reporting period amounted to MUSD 23.8 (MUSD 188.2) and is detailed in Note 4.

The reserve-based lending facility was successfully re-negotiated during the comparative period, resulting in the interest rate margin over LIBOR being reduced from 3.15 percent to a current rate of 2.25 percent effective as of 1 June 2018. The amendment of the interest rate margin resulted in an accounting gain of MUSD 183.7 in the comparative period in accordance with IFRS 9 that unwinds to the income statement over the remaining period of the facility.

The result on interest rate hedge settlements amounted to a gain of MUSD 22.5 (MUSD 0.1).

Finance costs

Finance costs for the reporting period amounted to MUSD 366.6 (MUSD 138.3) and are detailed in Note 5.

The net foreign currency exchange loss for the reporting period amounted to MUSD 237.7 (MUSD 1.2). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. Lundin Petroleum has hedged certain foreign currency capital expenditure amounts, foreign currency Corporate and Special Petroleum Tax amounts and foreign currency funding requirements for the share redemption against the US Dollar and for the reporting period, the net realised exchange loss on these settled foreign exchange hedges amounted to MUSD 46.5 (gain of MUSD 7.4).

The US Dollar strengthened with 5 percent against the Euro during the reporting period resulting in a net foreign currency 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 strengthened with less than 1 percent against the Euro in the reporting period, generating a net foreign currency exchange gain on an intercompany loan balance denominated in Norwegian Krone.

Interest expenses for the reporting period amounted to MUSD 54.7 (MUSD 68.7) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 79.3 (MUSD 64.9) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense was in line with the comparative period.

The amortisation of the deferred financing fees for the reporting period amounted to MUSD 15.8 (MUSD 13.5) and related to the fees incurred in establishing the reserve-based lending facility and the fees incurred in establishing the short-term MUSD 500 bridge facility that was temporarily in place from late July 2019 to the end of August 2019 to partly fund the share redemption transaction. The bridge facility was fully repaid at the end of August 2019 when the sale of 2.6 percent of Johan Sverdrup completed. The fees in relation to the reserve-based lending facility are being expensed over the expected life of that facility.

Loan facility commitment fees for the reporting period amounted to MUSD 8.9 (MUSD 9.7) and related mainly to the lower margin for commitment fees as agreed through the amendment of the facility effective as of 1 June 2018.

As a result of the successful re-negotiated reserve-based lending facility during the comparative period, loan modification fees amounting to MUSD 17.3 were incurred in the comparative period.

The unwinding of the loan modification gain for the reporting period amounted to MUSD 31.4 (MUSD 15.1) and related to the expensing of the accounting gain from the re-negotiated improved borrowing terms for the reserve-based lending facility over the period of usage of the facility.

Share in result of associate company

Share in result of associated company for the reporting period amounted to MUSD -1.3 (MUSD -0.6) and related to the share in the result of the investment in Mintley Caspian Ltd.

Tax

The overall tax charge for the reporting period amounted to MUSD 574.5 (MUSD 827.6) and is detailed in Note 6.

The current tax charge for the reporting period amounted to MUSD 80.5 (MUSD 54.7) and mainly related to Norway. The current tax charge for Norway related to Corporate Tax only with no current tax charge to the income statement in relation to the Special Petroleum Tax (SPT) as the Company continues to be sheltered from SPT tax losses. The SPT tax losses are expected to be fully utilized during the fourth quarter of 2019. The paid tax installments in Norway during the reporting period amounted to MUSD 35.1 which has in combination with the current tax charge for the period resulted in an increase in current tax liabilities compared to the comparative period.

The deferred tax charge for the reporting period amounted to MUSD 494.0 (MUSD 772.9) and related to Norway. The deferred tax amount arises primarily where there is a difference in depletion for tax and accounting purposes.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 21.4 and 78 percent. The effective tax rate for the reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange results, Norwegian financial items and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 5,321.7 (MUSD 5,341.1) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Norway	498.0	140.8	550.9	174.6	701.9
Development expenditure	**498.0**	**140.8**	550.9	174.6	701.9

Development expenditure of MUSD 498.0 (MUSD 550.9) was incurred in Norway during the reporting period, primarily on the Johan Sverdrup field. In addition an amount of MUSD 79.3 (MUSD 64.9) of interest was capitalised.

Exploration and appraisal expenditure in MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Norway	236.3	53.0	225.2	52.5	310.6
Exploration and appraisal expenditure	**236.3**	**53.0**	225.2	52.5	310.6

Exploration and appraisal expenditure of MUSD 236.3 (MUSD 225.2) was incurred in Norway during the reporting period, primarily for the exploration and appraisal wells as summarized on page 5.

Other tangible fixed assets amounted to MUSD 44.9 (MUSD 13.6) and are detailed in Note 8. Following the implementation of IFRS 16 with effective date 1 January 2019, the Company recognized right of use assets that amounted to MUSD 31.9 (MUSD —).

Goodwill associated with the accounting for the Edvard Grieg transaction during 2016 amounted to MUSD 128.1 (MUSD 128.1).

Financial assets amounted to MUSD 13.0 (MUSD 0.4) and are detailed in Note 9. The sale of 2.6 percent of Johan Sverdrup included a contingent consideration based on future reserve reclassifications and is due in 2026. This contingent consideration was fair valued by the Company and amounted to MUSD 12.3 (MUSD —).

Current assets

Inventories amounted to MUSD 35.7 (MUSD 36.5) and included both well supplies and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 250.2 (MUSD 216.6) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 201.7 (MUSD 153.7). Underlift amounted to MUSD 4.8 (MUSD 1.9) and was attributable to an underlift position on the producing fields, mainly relating to condensate from the Edvard Grieg field. Joint operations debtors relating to various joint venture receivables amounted to MUSD 14.1 (MUSD 17.0). Prepaid expenses and accrued income amounted to MUSD 28.7 (MUSD 26.9) and represented mainly prepaid operational and insurance expenditure. Other current assets amounted to MUSD 0.9 (MUSD 17.1) with the reduction mainly caused by the receipt during the reporting period of the short term receivable from IPC relating to certain working capital balances following the IPC spin-off.

Derivative instruments amounted to MUSD 1.3 (MUSD 34.0) and related to the marked-to-market gain on the outstanding interest rate hedge contracts due to be settled within twelve months.

Cash and cash equivalents amounted to MUSD 95.1 (MUSD 66.8). Cash balances are mainly held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 4,025.6 (MUSD 3,262.0) and are detailed in Note 11. Bank loans amounted to MUSD 4,150.0 (MUSD 3,465.0) and related to the outstanding loan under the reserve-based lending facility. Capitalised financing fees relating to the establishment of the facility amounted to MUSD 39.8 (MUSD 54.1) and are being amortised over the expected life of the facility. The capitalised loan modification gain relating to the re-negotiated improved borrowing terms for the lending facility during 2018 amounted to MUSD 112.1 (MUSD 148.9) and are being amortised over the expected life of the facility. The lease commitments amounted to MUSD 27.5 (MUSD —) and related to the long-term portion of the lease commitments following the implementation of IFRS 16 with effective date 1 January 2019. The short-term portion of the lease commitments was classified as current liabilities.

Provisions amounted to MUSD 493.4 (MUSD 489.1) and are detailed in Note 12. The provision for site restoration amounted to MUSD 489.3 (MUSD 483.9) and related to the long-term portion of the future decommissioning obligations. The short-term portion of the future decommissioning obligations was classified as current liabilities. The increase in site restoration reflects the additional liability for the Johan Sverdrup development project partly offset by the sale of 2.6 percent of Johan Sverdrup.

Deferred tax liabilities amounted to MUSD 2,374.5 (MUSD 2,103.8). The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

Derivative instruments amounted to MUSD 161.7 (MUSD 64.9) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled after twelve months.

Current liabilities

Current financial liabilities amounted to MUSD 5.0 (MUSD —) and are detailed in Note 11. Current financial liabilities related to the short-term portion of the lease commitments.

Dividends amounted to MUSD 209.5 (MUSD —) and related to the cash dividend approved by the AGM held on 29 March 2019 in Stockholm, which will be paid in quarterly installments.

Trade and other payables amounted to MUSD 220.0 (MUSD 200.9) and are detailed in Note 13. Overlift amounted to MUSD 7.1 (MUSD 1.7) and was attributable to an overlift position in relation to oil from the Alvheim Area and Edvard Grieg field. Joint operations creditors and accrued expenses amounted to MUSD 156.5 (MUSD 147.4) and related to activity in Norway. Other accrued expenses amounted to MUSD 34.1 (MUSD 17.6) and other current liabilities amounted to MUSD 13.3 (MUSD 7.6).

Derivative instruments amounted to MUSD 52.3 (MUSD 20.0) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Current tax liabilities amounted to MUSD 110.5 (MUSD 70.4) and related mainly to Corporate Tax due in Norway.

Current provisions amounted to MUSD 37.4 (MUSD 12.5) and are detailed in Note 12. The short-term portion of the future decommissioning obligations amounted to MUSD 32.6 (MUSD 6.6) mainly relating to the Brynhild field. The short-term portion of the provision for Lundin Petroleum's Unit Bonus Plan amounted to MUSD 4.8 (MUSD 5.9).

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 for the reporting period amounted to MSEK 18,965.6 (MSEK 1,605.0). The net result for the reporting period included MSEK 19,148.4 (MSEK 1,714.6) financial income as a result of received dividends from a subsidiary. The net result excluding received dividends amounted to MSEK -182.8 (MSEK -109.6).

The net result for the reporting period included general and administrative expenses of MSEK 170.5 (MSEK 124.4) and net finance costs of MSEK 21.8 (finance income of MSEK 5.6) when excluding the received dividends as mentioned above.

Pledged assets of MSEK 55,118.9 (MSEK 55,118.9) relate to the carrying value of the pledge of the shares in respect of the reserve-based lending facility entered into by its wholly-owned subsidiary Lundin Petroleum Holding BV, see also the Liquidity section below.

Related Party Transactions

During the reporting period, the Group has entered into various transactions with related parties on a commercial basis including the transactions described below. Following the redemption of 16 percent of the outstanding Lundin Petroleum shares previously held by Equinor, as approved at the Extraordinary General Meeting of Lundin Petroleum held on 31 July 2019, the Equinor Group is no longer considered a related party. The related party transactions with Equinor as described below therefore relate to the period until end July.

The Group has purchased oil from the Equinor group on an arm's-length basis amounting to MUSD — (MUSD 247.5).

The Group has sold oil and related products to the Equinor group on an arm's-length basis amounting to MUSD 122.0 (MUSD 760.7).

As at the date of the IPC spin-off, the Group had a residual receivable for working capital from IPC of MUSD 27.4 of which the last portion was received during the reporting period.

Liquidity

In February 2016, Lundin Petroleum entered into a committed seven year senior secured reserve-based lending facility of USD 5.0 billion. The facility was amended during the second quarter of 2018 resulting in the interest rate margin over LIBOR being reduced from 3.15 percent to a current rate of 2.25 percent. The facility is secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every twelve 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, a pledge over the Company's working interest in some production licenses and a charge over some of the bank accounts of the pledged companies.

Contingent liabilities

The Swedish Prosecution Authority issued a notification of a corporate fine and forfeiture of economic benefits against Lundin Petroleum in relation to past operations in Sudan from 1997 to 2003. The notification indicated that the Prosecutor might seek a corporate fine of SEK 3 million and forfeiture of economic benefits from the alleged offense in the amount of SEK 3,282 million, based on the profit of the sale of the Block 5A asset in 2003 of SEK 720 million. Any potential corporate fine or forfeiture would only be imposed after the conclusion of a trial, should one occur. The investigation is in its tenth year and Lundin Petroleum remains convinced that there are absolutely no grounds for any allegations of wrongdoing by any Company representative and the Company will firmly contest any corporate fine or forfeiture of economic benefits. The Company considers this to be a contingent liability and therefore no provision has been recognised.

Subsequent Events

During October 2019, Lundin Petroleum entered into additional forward currency hedges to meet part of its future NOK capital requirements relating to its committed development projects and to meet part of its future NOK Corporate and Special Petroleum Tax requirements as summarized below:

Buy	Sell	Average contractual Exchange rate	Settlement period
MNOK 4,899.0	MUSD 536.7	NOK 9.13:USD 1	Jan 2020 — Dec 2020
MNOK 340.0	MUSD 37.3	NOK 9.12:USD 1	Jan 2021 — Dec 2021
MNOK 230.0	MUSD 25.2	NOK 9.13:USD 1	Jan 2022 — Dec 2022
MNOK 120.0	MUSD 13.2	NOK 9.09:USD 1	Jan 2023 — Dec 2023
MNOK 300.0	MUSD 33.0	NOK 9.09:USD 1	Jan 2024 — Dec 2024

In October 2019, the Gladsheim prospect in PL921 in the Northern North Sea was drilled and was dry and will be expensed in the fourth quarter.

In October 2019, the Company signed an agreement with Sognekraft AS to acquire a 50 percent non-operated interest in the Leikanger Hydropower project, in midwest Norway. Leikanger will produce around 208 GWh per annum gross, once it is fully operational in 2021, from a river run off hydropower generation scheme and will more than offset the non-renewable energy required for our net share of Johan Sverdrup Phase 1 power consumption. The investment to Lundin Petroleum is approximately MUSD 60 over the three year period 2019 to 2021 and the project will be Free Cash Flow positive from 2022. The project will also provide a natural hedge to the electricity price fluctuation; Johan Sverdrup electricity share of the operating costs accounts for approximately 15 percent of the total operating costs. The completion of the transaction remains subject to customary closing conditions, with closing expected to occur in early 2020.

Share Data

Lundin Petroleum AB's issued share capital amounted to SEK 3,478,713 represented by 285,924,614 shares with a quota value of SEK 0.01 each (rounded off) with the issued share capital including a bonus issue (sw. fondemission) of SEK 556,594 during the reporting period, to restore the share capital of Lundin Petroleum to the same amount as immediately prior to the share redemption as approved by the EGM of Lundin Petroleum held on 31 July 2019.

During 2017, Lundin Petroleum purchased 1,233,310 of its own shares at an average price of SEK 186.14 based on the approval granted at the AGM 2017. During 2018, Lundin Petroleum purchased an additional 640,000 of its own shares at an average price of SEK 186.77 based on the approval granted at the AGM 2017 resulting in 1,873,310 of its own shares held by the Company.

The AGM of Lundin Petroleum held on 29 March 2019 in Stockholm approved a cash dividend distribution for the year 2018 of USD 1.48 per share, to be paid in quarterly installments of USD 0.37 per share. Before payment, each quarterly dividend of USD 0.37 per share shall be converted into a SEK amount, and paid out in SEK, based on the USD to SEK exchange rate published by Sweden's central bank (Riksbanken) four business days prior to each record date (rounded off to the nearest whole SEK 0.01 per share). The final USD equivalent amount received by the shareholders may therefore slightly differ depending on what the USD to SEK exchange rate is on the date of the dividend payment. Based on the number of shares outstanding, excluding own shares held by the Company, the approved dividend distribution amounted to MSEK 4,638.7, equaling MUSD 501.0 based on the exchange rate on the date of AGM approval.

The first dividend payment was made on 5 April 2019, the second dividend payment was made on 8 July 2019 and the third dividend payment was made on 7 October 2019. The fourth dividend payment is expected to be paid around 9 January 2020, with an expected record date of 3 January 2020 and an expected ex-dividend date of 2 January 2020.

In order to comply with Swedish company law, a maximum total SEK amount shall be pre-determined to ensure that the dividend distributed does not exceed the available distributable reserves of the Company and such maximum amount for the 2018 dividend has been set to a cap of SEK 7.665 billion (i.e., SEK 1.916 billion per quarter). If the total dividend would exceed the cap of SEK 7.665 billion, the dividend will be automatically adjusted downwards so that the total dividend corresponds to the cap of SEK 7.665 billion.

The EGM of Lundin Petroleum held on 31 July 2019 in Stockholm approved the redemption of 54,461,831 shares previously held by Equinor, amounting to 16 percent of the outstanding shares at a price of SEK 266.40 per share. The total number of shares in issue decreased because of the share redemption from 340,386,445 shares to 285,924,614 shares. The outstanding dividend liability relating to the third and fourth dividend payment as approved by the AGM of Lundin Petroleum held on 29 March 2019 decreased with 16 percent as a result of the share redemption.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2018 Annual Report and in the materials provided to shareholders in respect of the 2019 AGM, available on www.lundin-petroleum.com

Unit Bonus Plan

The number of units relating to the awards made in 2017, 2018 and 2019 under the Unit Bonus Plan outstanding as at 30 September 2019 were 90,813, 145,816 and 190,587 respectively.

Performance Based Incentive Plan

The AGM 2019 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 2019 and the 2019 award is accounted for from the second half of 2019. The total outstanding number of awards at 30 September 2019 was 316,855 and the awards vest over three years from 1 July 2019 subject to certain performance conditions being met. Each original award was fair valued at the date of grant at SEK 169.00 using an option pricing model.

The 2018 plan is effective from 1 July 2018 and the total outstanding number of awards at 30 September 2019 was 271,159 and the awards vest over three years from 1 July 2018 subject to certain performance conditions being met. Each original award was fair valued at the date of grant at SEK 167.10 using an option pricing model.

The 2017 plan is effective from 1 July 2017 and the total outstanding number of awards at 30 September 2019 was 350,419 and the awards vest over three years from 1 July 2017 subject to certain performance conditions being met. Each original award was fair valued at the date of grant at SEK 100.10 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).

IFRS 16 has come into effect with effective date 1 January 2019. IFRS16 Leases, addresses the recognition in the balance sheet of each contract, with some exceptions, that meets the definition of a lease as a right of use asset and lease liability, while lease payments are to be reflected as interest expense and a reduction of lease liability. The Group has made the following transition choices in relation to IFRS 16: (a) application of the modified retrospective method, (b) right of use assets are measured at an amount equal to the lease liability and (c) leases with a less than 12 months remaining lease term at year end 2018 are not reflected as leases. The Group has made the following application policy choice: short term leases (less than 12 months) and leases of low value assets are not reflected in the balance sheet, but will be expensed as incurred.

Lundin Petroleum has assessed the impact of IFRS 16 on the financial statements of the Group and only identified one relevant contract containing a lease with no material impact on the financial statements of the Group. The Company accounted for right of use assets and lease commitments amounting to MUSD 36.6 per effective date 1 January 2019.

Lundin Petroleum has changed its accounting principle for revenue recognition relating to under/overlift balances. The Group previously recognized income based on its produced volumes (entitlement method) for the period. Lundin Petroleum has decided to change the accounting treatment of such under/overlift so that from 1 April 2019 the income will reflect sold volumes (sales method).

This means that changes in under/overlift balances are no longer reported as other income valued at market price, but will instead be reported as an adjustment to cost valued at production cost including depletion. Comparative figures have been restated in line with IAS 8 as per the table below:

Restated net result previous quarters MUSD	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Reported net result previous quarters	54.9	-105.3	62.6	36.0	228.8
Changes due to change in accounting principle					
Adjustment in other income	-7.5	41.2	-31.8	4.4	9.5
Adjustment in production costs	1.2	-9.0	5.1	0.2	-3.3
Adjustment in deferred tax	4.9	-25.1	20.8	-3.6	-4.8
Impact of change in accounting principle	-1.4	7.1	-5.9	1.0	1.4
Restated net result previous quarters	53.5	-98.2	56.7	37.0	230.2

Apart from the changes in accounting principles as mentioned above, 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 2018.

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 2018 Annual Report.

Derivative financial instruments

Lundin Petroleum has entered into forward currency hedges to meet part of its future NOK capital requirements relating to its committed field development projects and to meet part of its future NOK Corporate Tax requirements. At 30 September 2019, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual Exchange rate	Settlement period
MNOK 1,253.0	MUSD 152.0	NOK 8.24:USD 1	Oct 2019 – Dec 2019
MNOK 2,405.0	MUSD 306.0	NOK 7.86:USD 1	Jan 2020 – Dec 2020
MNOK 2,130.0	MUSD 272.7	NOK 7.81:USD 1	Jan 2021 – Dec 2021
MNOK 1,200.0	MUSD 158.2	NOK 7.59:USD 1	Jan 2022 – Dec 2022
MNOK 410.0	MUSD 51.0	NOK 8.04:USD 1	Jan 2023 – Dec 2023

Lundin Petroleum entered into interest rate hedge contracts and at 30 September 2019 had outstanding interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR average rate per annum	Settlement period
3,000	1.42%	Oct 2019 – Dec 2019
3,300	1.96%	Jan 2020 – Dec 2020
3,100	2.28%	Jan 2021 – Dec 2021
2,900	2.41%	Jan 2022 – Dec 2022
2,000	1.75%	Jan 2023 – Dec 2023
1,500	1.91%	Jan 2024 – Dec 2024

Under IFRS 9, subject to hedge effectiveness testing, all of the hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

Exchange Rates

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

	30 Sep 2019		30 Sep 2018		31 Dec 2018	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.6957	9.0874	8.0295	8.1777	8.1329	8.6885
1 USD equals Euro	0.8899	0.9184	0.8369	0.8639	0.8464	0.8734
1 USD equals SEK	9.4060	9.8226	8.5757	8.9055	8.6921	8.9562

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2019- 30 Sep 2019 9 months	1 Jul 2019- 30 Sep 2019 3 months	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Revenue and other income	1					
Revenue		1,418.3	450.5	1,963.3	596.6	2,607.9
Gain from sale of assets		756.7	756.7	–	–	–
Other income		24.0	7.8	25.2	8.0	32.8
		2,199.0	**1,215.0**	1,988.5	604.6	2,640.7
Cost of sales						
Production costs	2	-118.6	-41.6	-103.8	-31.8	-152.4
Depletion and decommissioning costs		-301.6	-105.0	-341.5	-108.8	-458.0
Exploration costs		-84.7	-13.8	-6.1	-0.2	-53.2
Purchase of crude oil from third parties		-84.3	–	-417.2	-92.4	-533.8
Gross profit	3	**1,609.8**	**1,054.6**	1,119.9	371.4	1,443.3
General, administration and depreciation expenses		-21.6	-7.1	-17.7	-4.2	-24.6
Operating profit		**1,588.2**	**1,047.5**	1,102.2	367.2	1,418.7
Net financial items						
Finance income	4	23.8	-27.7	188.2	-9.2	192.2
Finance costs	5	-366.6	-288.2	-138.3	-42.2	-345.4
		-342.8	**-315.9**	49.9	-51.4	-153.2
Share in result of associated company		-1.3	-0.3	-0.6	-0.6	-1.3
Profit before tax		**1,244.1**	**731.3**	1,151.5	315.2	1,264.2
Income tax	6	-574.5	-211.4	-827.6	-258.5	-1,038.5
Net result		**669.6**	**519.9**	323.9	56.7	225.7
Attributable to:						
Shareholders of the Parent Company		669.6	519.9	323.9	56.7	225.7
Non-controlling interest		–	–	–	–	–
		669.6	**519.9**	323.9	56.7	225.7
Earnings per share – USD		2.05	1.72	0.96	0.17	0.67
Earnings per share fully diluted – USD		2.05	1.71	0.95	0.16	0.66
Adjusted earnings per share – USD		0.53	0.15	0.65	0.22	0.87
Adjusted earnings per share fully diluted – USD		0.53	0.15	0.65	0.22	0.87

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Net result	**669.6**	**519.9**	323.9	56.7	225.7
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	74.1	61.5	15.9	3.6	1.5
Cash flow hedges	-172.1	-102.5	44.5	5.3	-74.1
Other comprehensive income, net of tax	**-98.0**	**-41.0**	60.4	8.9	-72.6
Total comprehensive income	**571.6**	**478.9**	384.3	65.6	153.1
Attributable to:					
Shareholders of the Parent Company	571.6	478.9	384.3	65.6	153.1
Non-controlling interest	–	–	–	–	–
	571.6	**478.9**	384.3	65.6	153.1

Consolidated Balance Sheet

Expressed in MUSD	Note	**30 September 2019**	31 December 2018
ASSETS			
Non-current assets			
Oil and gas properties	7	5,321.7	5,341.1
Other tangible fixed assets	8	44.9	13.6
Goodwill		128.1	128.1
Financial assets	9	13.0	0.4
Derivative instruments	14	–	2.7
Total non-current assets		**5,507.7**	5,485.9
Current assets			
Inventories		35.7	36.5
Trade and other receivables	10	250.2	216.6
Derivative instruments	14	1.3	34.0
Cash and cash equivalents		95.1	66.8
Total current assets		**382.3**	353.9
TOTAL ASSETS		**5,890.0**	5,839.8
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		**-1,799.9**	-383.8
Liabilities			
Non-current liabilities			
Financial liabilities	11	4,025.6	3,262.0
Provisions	12	493.4	489.1
Deferred tax liabilities		2,374.5	2,103.8
Derivative instruments	14	161.7	64.9
Total non-current liabilities		**7,055.2**	5,919.8
Current liabilities			
Financial liabilities	11	5.0	–
Dividends		209.5	–
Trade and other payables	13	220.0	200.9
Derivative instruments	14	52.3	20.0
Current tax liabilities		110.5	70.4
Provisions	12	37.4	12.5
Total current liabilities		**634.7**	303.8
Total liabilities		**7,689.9**	6,223.6
TOTAL EQUITY AND LIABILITIES		**5,890.0**	5,839.8

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Cash flows from operating activities					
Net result	669.6	519.9	323.9	56.7	225.7
Adjustments for:					
Gain from sale of assets	-756.7	-756.7	–	–	–
Exploration costs	84.7	13.8	6.1	0.2	53.2
Depletion, depreciation and amortisation	306.6	106.6	343.5	109.4	460.6
Current tax	80.5	36.7	54.7	46.0	90.4
Deferred tax	494.0	174.7	772.9	212.5	948.1
Long-term incentive plans	10.1	3.4	14.1	4.2	14.6
Foreign currency exchange gain/ loss	191.3	234.9	1.0	10.7	162.5
Interest expense	54.7	22.8	68.7	19.6	88.7
Loan modification gain	–	–	-183.7	–	-183.7
Loan modification fees	–	–	17.3	–	17.3
Unwinding of loan modification gain	31.4	10.3	15.1	11.4	26.1
Amortisation of deferred financing fees	15.8	7.4	13.5	4.3	17.8
Other	13.4	4.2	8.4	4.8	12.8
Interest received	1.3	0.5	0.8	0.2	1.1
Interest paid	-118.2	-35.0	-133.1	-41.2	-176.0
Income taxes paid / received	-35.4	-19.6	-5.8	-5.1	-15.8
Changes in working capital	-57.8	-93.1	-31.8	44.5	-25.1
Total cash flows from operating activities	**985.3**	**230.8**	1,285.6	478.2	1,718.3
Cash flows from investing activities					
Investment in oil and gas properties	-821.9	-237.6	-801.7	-248.0	-1,060.1
Investment in other fixed assets	-1.4	-0.5	-2.7	-0.7	-3.2
Investment in other shares and participations	-0.3	-0.3	9.3	–	9.3
Disposal of fixed assets[1]	959.0	959.0	–	–	–
Decommissioning costs paid	-2.8	-0.9	-0.8	-0.8	-1.3
Total cash flows from investing activities	**132.6**	**719.7**	-795.9	-249.5	-1,055.3
Cash flows from financing activities					
Changes in long-term bank loans	685.0	690.0	-310.0	-250.0	-490.0
Changes in lease commitments[2]	-2.6	-0.8	–	–	–
Financing fees paid	-3.3	-3.3	-17.3	-0.4	-17.3
Dividends paid	-250.5	-125.3	-153.1	–	-153.1
Share redemption	-1,517.2	-1,517.2	–	–	–
Purchase of own share	–	–	-14.3	–	-14.3
Total cash flows from financing activities	**-1,088.6**	**-956.6**	-494.7	-250.4	-674.7
Change in cash and cash equivalents	29.3	-6.1	-5.0	-21.7	-11.7
Cash and cash equivalents at the beginning of the period	66.8	100.7	71.4	96.5	71.4
Currency exchange difference in cash and cash equivalents	-1.0	0.5	8.7	0.3	7.1
Cash and cash equivalents at the end of the period	**95.1**	**95.1**	75.1	75.1	66.8

[1] Cash received on the divestment of a 2.6 percent working interest in the Johan Sverdrup field on closing including interest and pro and contra funding settlement from effective date to completion date as well as working capital balances and incurred expenses

[2] Changes in lease commitments subsequent to initial recognition of lease commitments based on IFRS16

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Dividends	Total equity
At 1 January 2018	**0.5**	**82.2**	**-433.5**	**–**	**-350.8**
Change of accounting principle[1]	–	–	-3.4	–	-3.4
Restated equity at 1 January 2018	**0.5**	**82.2**	**-436.9**	**–**	**-354.2**
Comprehensive income					
Net result	–	–	323.9	–	323.9
Other comprehensive income	–	60.4	–	–	60.4
Total comprehensive income	**–**	**60.4**	**323.9**	**–**	**384.3**
Transactions with owners					
Distributions	–	–	–	-153.1	-153.1
Purchase of own shares	–	-14.3	–	–	-14.3
Share based payments	–	-20.8	–	–	-20.8
Value of employee services	–	–	4.4	–	4.4
Total transactions with owners	**–**	**-35.1**	**4.4**	**-153.1**	**-183.8**
At 30 September 2018	**0.5**	**107.5**	**-108.6**	**-153.1**	**-153.7**
Comprehensive income					
Net result	–	–	-98.2	–	-98.2
Other comprehensive income	–	-133.0	–	–	-133.0
Total comprehensive income	**–**	**-133.0**	**-98.2**	**–**	**-231.2**
Transactions with owners					
Value of employee services	–	–	1.1	–	1.1
Total transaction with owners	**–**	**–**	**1.1**	–	**1.1**
At 31 December 2018	**0.5**	**-25.5**	**-205.7**	**-153.1**	**-383.8**
Transfer of prior year dividends	–	-153.1	–	153.1	–
Comprehensive income					
Net result	–	–	669.6	–	669.6
Other comprehensive income	–	-98.0	–	–	-98.0
Total comprehensive income	**–**	**-98.0**	**669.6**	**–**	**571.6**
Transactions with owners					
Distributions	–	–	–	-501.0	-501.0
Share redemption	-0.1	-1,476.9	–	–	-1,477.0
Bonus issue (sw. fondemission)	0.1	-0.1	–	–	–
Share based payments	–	-13.7	–	–	-13.7
Value of employee services	–	–	4.0	–	4.0
Total transaction with owners	**–**	**-1,490.7**	**4.0**	**-501.0**	**-1,987.7**
At 30 September 2019	**0.5**	**-1,767.3**	**467.9**	**-501.0**	**-1,799.9**

[1] Relates to change in accounting principle for revenue recognition relating to under/overlift balances as mentioned on page 13.

Notes to the Consolidated Financial Statements

Note 1 — Revenue and other income MUSD	1 Jan 2019- 30 Sep 2019 9 months	1 Jul 2019- 30 Sep 2019 3 months	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Revenue					
Crude oil from own production	1,243.0	431.7	1,396.9	435.7	1,877.6
Crude oil from third party activities	84.3	–	419.1	92.6	536.1
Condensate	23.6	0.2	34.5	25.5	41.8
Gas	67.4	18.6	112.8	42.8	152.4
Sales of oil and gas	**1,418.3**	**450.5**	1,963.3	596.6	2,607.9
Gain from sale of assets	756.7	756.7	–	–	–
Other income	24.0	7.8	25.2	8.0	32.8
Revenue and other income	**2,199.0**	**1,215.0**	1,988.5	604.6	2,640.7

Note 2 — Production costs MUSD	1 Jan 2019- 30 Sep 2019 9 months	1 Jul 2019- 30 Sep 2019 3 months	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Cost of operations	81.9	25.5	74.0	26.6	102.5
Tariff and transportation expenses	30.7	10.9	25.8	8.6	35.2
Change in under/over lift position	2.6	4.2	-2.0	-5.1	7.0
Change in inventory position	0.3	–	0.6	–	0.6
Other	3.1	1.0	5.4	1.7	7.1
Production costs	**118.6**	**41.6**	103.8	31.8	152.4

Note 3 — Segment information MUSD	1 Jan 2019- 30 Sep 2019 9 months	1 Jul 2019- 30 Sep 2019 3 months	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Norway					
Crude oil from own production	1,243.0	431.7	1,396.9	435.7	1,877.6
Condensate	23.6	0.2	34.5	25.5	41.8
Gas	67.4	18.6	112.8	42.8	152.4
Revenue	**1,334.0**	**450.5**	1,544.2	504.0	2,071.8
Gain from sale of assets	756.7	756.7	–	–	–
Other income	24.0	7.8	25.2	8.0	32.8
Revenue and other income	**2,114.7**	**1,215.0**	1,569.4	512.0	2,104.6
Production costs	-118.6	-41.6	-103.8	-31.8	-152.4
Depletion and decommissioning costs	-301.6	-105.0	-341.5	-108.8	-458.0
Exploration costs	-84.7	-13.8	-6.1	-0.2	-53.2
Gross profit	**1,609.8**	**1,054.6**	1,118.0	371.2	1,441.0
Other					
Crude oil from third party activities	84.3	–	419.1	92.6	536.1
Revenue	**84.3**	**–**	419.1	92.6	536.1
Purchase of crude oil from third parties	-84.3	–	-417.2	-92.4	-533.8
Gross profit	**0.0**	**–**	1.9	0.2	2.3

Note 3 — Segment information cont. MUSD	**1 Jan 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Total					
Crude oil from own production	1,243.0	431.7	1,396.9	435.7	1,877.6
Crude oil from third party activities	84.3	—	419.1	92.6	536.1
Condensate	23.6	0.2	34.5	25.5	41.8
Gas	67.4	18.6	112.8	42.8	152.4
Revenue	**1,418.3**	**450.5**	1,963.3	596.6	2,607.9
Gain from sale of assets	756.7	756.7	—	—	—
Other income	24.0	7.8	25.2	8.0	32.8
Revenue and other income	**2,199.0**	**1,215.0**	1,988.5	604.6	2,640.7
Production costs	-118.6	-41.6	-103.8	-31.8	-152.4
Depletion and decommissioning costs	-301.6	-105.0	-341.5	-108.8	-458.0
Exploration costs	-84.7	-13.8	-6.1	-0.2	-53.2
Purchase of crude oil from third parties	-84.3	—	-417.2	-92.4	-533.8
Gross profit	**1,609.8**	**1,054.6**	1,119.9	371.4	1,443.3

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 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Foreign currency exchange gain, net	—	-34.7	—	-9.6	—
Loan modification gain	—	—	183.7	—	183.7
Interest income	1.3	0.5	1.1	0.3	1.7
Gain on interest rate hedge settlement	22.5	6.5	0.1	0.1	3.5
Other	—	—	3.3	—	3.3
Finance income	**23.8**	**-27.7**	188.2	-9.2	192.2

Note 5 — Finance costs MUSD	**1 Jan 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Foreign currency exchange loss, net	237.7	237.7	1.2	1.2	164.9
Interest expense	54.7	22.8	68.7	19.6	88.7
Loss on interest rate hedge settlement	—	—	—	-1.7	—
Unwinding of site restoration discount	13.4	4.4	12.0	4.3	16.4
Amortisation of deferred financing fees	15.8	7.4	13.5	4.3	17.8
Loan facility commitment fees	8.9	1.9	9.7	2.9	13.0
Loan modification fees	—	—	17.3	—	17.3
Unwinding of loan modification gain	31.4	10.3	15.1	11.4	26.1
Other	4.7	3.7	0.8	0.2	1.2
Finance costs	**366.6**	**288.2**	138.3	42.2	345.4

Note 6 — Income tax MUSD	**1 Jan 2019-30 Sep 2019 9 months**	**1 Jul 2019-30 Sep 2019 3 months**	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2018-31 Dec 2018 12 months
Current tax	80.5	36.7	54.7	46.0	90.4
Deferred tax	494.0	174.7	772.9	212.5	948.1
Income tax	**574.5**	**211.4**	827.6	258.5	1,038.5

Note 7 — Oil and gas properties

MUSD	30 Sep 2019	31 Dec 2018
Norway		
Producing assets	1,412.8	1,759.3
Assets under development	3,072.1	2,750.1
Capitalised exploration and appraisal expenditure	836.8	831.7
	5,321.7	5,341.1

Note 8 — Other tangible fixed assets

MUSD	30 Sep 2019	31 Dec 2018
Right of use assets	31.9	–
Other	13.0	13.6
	44.9	13.6

Note 9 — Financial assets

MUSD	30 Sep 2019	31 Dec 2018
Contingent consideration	12.3	–
Other shares and participations	0.3	–
Other	0.4	0.4
	13.0	0.4

Note 10 — Trade and other receivables

MUSD	30 Sep 2019	31 Dec 2018
Trade receivables	201.7	153.7
Underlift	4.8	1.9
Joint operations debtors	14.1	17.0
Prepaid expenses and accrued income	28.7	26.9
Other	0.9	17.1
	250.2	216.6

Note 11 — Financial liabilities

MUSD	30 Sep 2019	31 Dec 2018
Non-current:		
Bank loans	4,150.0	3,465.0
Capitalised financing fees	-39.8	-54.1
Capitalised loan modification gain	-112.1	-148.9
Lease commitments	27.5	–
	4,025.6	3,262.0
Current:		
Lease commitments	5.0	–
	5.0	–
	4,030.6	3,262.0

Note 12 — Provisions

MUSD	30 Sep 2019	31 Dec 2018
Non-current:		
Site restoration	489.3	483.9
Long-term incentive plans	1.7	2.4
Other	2.4	2.8
	493.4	489.1
Current:		
Site restoration	32.6	6.6
Long-term incentive plans	4.8	5.9
	37.4	12.5
	530.8	501.6

Note 13 — Trade and other payables

MUSD	**30 Sep 2019**	31 Dec 2018
Trade payables	9.0	26.6
Overlift	7.1	1.7
Joint operations creditors and accrued expenses	156.5	147.4
Other accrued expenses	34.1	17.6
Other	13.3	7.6
	220.0	200.9

Note 14 – Financial instruments

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

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

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

30 September 2019

MUSD	Level 1	Level 2	Level 3
Assets			
Contingent consideration	–	–	12.3
Derivative instruments — non-current	–	–	–
Derivative instruments — current	–	1.3	–
	–	**1.3**	**12.3**
Liabilities			
Derivative instruments — non-current	–	161.7	–
Derivative instruments — current	–	52.3	–
	–	**214.0**	**–**

31 December 2018

MUSD	Level 1	Level 2	Level 3
Assets			
Derivative instruments — non-current	–	2.7	–
Derivative instruments — current	–	34.0	–
	–	36.7	**–**
Liabilities			
Derivative instruments — non-current	–	64.9	–
Derivative instruments — current	–	20.0	–
	–	84.9	**–**

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

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

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Revenue	9.5	1.0	9.2	0.9	21.0
General and administration expenses	-170.5	-83.9	-124.4	-57.6	-180.9
Operating loss	**-161.0**	**-82.9**	-115.2	-56.7	-159.9
Net financial items					
Finance income	19,159.8	14,520.8	1,720.6	-0.3	1,818.1
Finance costs	-33.2	-33.1	-0.4	-0.2	-0.4
	19,126.6	**14,487.7**	1,720.2	-0.5	1,817.7
Profit before tax	**18,965.6**	**14,404.8**	1,605.0	-57.2	1,657.8
Income tax	–	–	–	–	–
Net result	**18,965.6**	**14,404.8**	1,605.0	-57.2	1,657.8

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Net result	**18,965.6**	**14,404.8**	1,605.0	-57.2	1,657.8
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**18,965.6**	**14,404.8**	1,605.0	-57.2	1,657.8
Attributable to:					
Shareholders of the Parent Company	18,965.6	14,404.8	1,605.0	-57.2	1,657.8
	18,965.6	**14,404.8**	1,605.0	-57.2	1,657.8

Parent Company Balance Sheet

Expressed in MSEK	**30 September 2019**	31 December 2018
ASSETS		
Non-current assets		
Shares in subsidiaries	55,118.9	55,118.9
Other tangible fixed assets	0.4	0.4
Total non-current assets	**55,119.3**	55,119.3
Current assets		
Receivables	2,260.5	5.4
Cash and cash equivalents	36.9	29.5
Total current assets	**2,297.4**	34.9
TOTAL ASSETS	**57,416.7**	55,154.2
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	55,322.9	55,120.8
Non-current liabilities		
Provisions	0.7	0.7
Total non-current liabilities	**0.7**	0.7
Current liabilities		
Dividends	2,057.8	–
Other liabilities	35.3	32.7
Total current liabilities	**2,093.1**	32.7
Total liabilities	**2,093.8**	33.4
TOTAL EQUITY AND LIABILITIES	**57,416.7**	55,154.2

Parent Company Cash Flow Statement

Expressed in MSEK	1 Jan 2019- 30 Sep 2019 9 months	1 Jul 2019- 30 Sep 2019 3 months	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Cash flow from operations					
Net result	18,965.6	14,404.8	1,605.0	-57.2	1,657.8
Adjustment for non-cash related items	-2,329.4	1,149.4	-5.0	0.6	-4.8
Changes in working capital	201.3	121.9	-105.5	55.1	-159.9
Total cash flow from operations	**16,837.5**	**15,676.1**	1,494.5	-1.5	1,493.1
Cash flow from investing					
Investments in other fixed assets	-0.1	-0.1	-0.1	—	-0.4
Total cash flow from investing	**-0.1**	**-0.1**	-0.1	—	-0.4
Cash flow from financing					
Dividends paid	-2,322.2	-1,161.1	-1,354.1	—	-1,354.1
Share redemption	-14,510.3	-14,510.3	—	—	—
Purchase of own shares	—	—	-119.5	—	-119.5
Total cash flow from financing	**-16,832.5**	**-15,671.4**	-1,473.6	—	-1,473.6
Change in cash and cash equivalents	4.9	4.6	20.8	-1.5	19.1
Cash and cash equivalents at the beginning of the period	29.5	30.6	4.8	33.4	4.8
Currency exchange difference in cash and cash equivalents	2.5	1.7	6.0	-0.3	5.6
Cash and cash equivalents at the end of the period	**36.9**	**36.9**	31.6	31.6	29.5

Parent Company Statement of Changes in Equity

	Restricted equity		Unrestricted equity				
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Dividends	Total	Total equity
Balance at 1 January 2018	**3.5**	**861.3**	**6,599.2**	**47,472.6**	**—**	**54,071.8**	**54,936.6**
Total comprehensive income	**—**	**—**	**—**	**1,605.0**	**—**	**1,605.0**	**1,605.0**
Transactions with owners							
Distributions	—	—	—	—	-1,354.1	-1,354.1	-1,354.1
Purchase of own shares	—	—	-119.5	—	—	-119.5	-119.5
Total transactions with owners	—	**—**	**-119.5**	**—**	**-1,354.1**	**-1,473.6**	**-1,473.6**
Balance at 30 September 2018	**3.5**	**861.3**	**6,479.7**	**49,077.6**	**-1,354.1**	**54,203.2**	**55,068.0**
Total comprehensive income	**—**	**—**	**—**	**52.8**	**—**	**52.8**	**52.8**
Transactions with owners							
Distributions	—	—	—	—	—	—	—
Total transactions with owners	**—**	**—**	—	**—**	—	—	—
Balance at 31 December 2018	**3.5**	**861.3**	**6,479.7**	**49,130.4**	**-1,354.1**	**54,256.0**	**55,120.8**
Transfer of prior year dividends	—	—	—	-1,354.1	1,354.1	—	—
Total comprehensive income	**—**	**—**	**—**	**18,965.6**	**—**	**18,965.6**	**18,965.6**
Transactions with owners							
Distributions	—	—	—	—	-4,638.7	-4,638.7	-4,638.7
Share redemption	-0.6	—	—	-14,124.2	—	-14,124.2	-14,124.8
Bonus issue (sw. fondemission)	0.6	—	—	-0.6	—	-0.6	—
Total transactions with owners	**—**	**—**	—	**-14,124.8**	**-4,638.7**	**-18,763.5**	**-18,763.5**
Balance at 30 September 2019	**3.5**	**861.3**	**6,479.7**	**52,617.1**	**-4,638.7**	**54,458.1**	**55,322.9**

Key Financial Data

Lundin Petroleum discloses alternative performance measures as part of its financial statements prepared in accordance with ESMA's (European Securities and Markets Authority) guidelines. Lundin Petroleum believes that the alternative performance measures provide useful supplement information to management, investors, security analysts and other stakeholders and are meant to provide an enhanced insight into the financial development of Lundin Petroleum's business operations and to improve comparability between periods. Reconciliations of relevant alternative performance measures are provided on the following page. Definitions of the performance measures are provided under the key ratio definitions below:

Financial data MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Revenue and other income	2,199.0	1,215.0	1,988.5	604.6	2,640.7
Operating cash flow[1]	1,158.9	380.0	1,412.8	434.4	1,864.1
EBITDA[1]	1,222.9	411.3	1,451.8	476.8	1,932.5
Free cash flow	1,117.9	950.5	489.7	228.7	663.0
Net result	669.6	519.9	323.9	56.7	225.7
Adjusted net result	173.8	45.4	220.1	75.1	295.3
Net debt	4,054.9	4,054.9	3,569.9	3,569.9	3,398.2
Data per share USD					
Shareholders' equity per share	-6.34	-6.34	-0.45	-0.45	-1.13
Operating cash flow per share[1]	3.55	1.25	4.17	1.28	5.51
EBITDA per share[1]	3.75	1.36	4.29	1.41	5.71
Free cash flow per share	3.42	2.91	1.45	0.68	1.96
Earnings per share	2.05	1.72	0.96	0.17	0.67
Earnings per share fully diluted	2.05	1.71	0.95	0.16	0.66
Adjusted earnings per share	0.53	0.15	0.65	0.22	0.87
Adjusted earnings per share fully diluted	0.53	0.15	0.65	0.22	0.87
Dividend per share[2]	0.74	0.74	0.45	–	0.45
Number of shares issued at period end	285,924,614	285,924,614	340,386,445	340,386,445	340,386,445
Number of shares in circulation at period end	284,051,304	284,051,304	338,513,135	338,513,135	338,513,135
Weighted average number of shares for the period	326,543,502	302,994,550	338,618,911	338,513,135	338,592,250
Weighted average number of shares for the period fully diluted	327,263,582	303,534,682	339,588,763	339,223,597	339,513,634
Share price					
Share price at period end in SEK	295.30	295.30	340.20	340.20	221.40
Share price at period end in USD[3]	30.06	30.06	38.20	38.20	24.72
Key ratios					
Return on equity (%)[4]	–	–	–	–	–
Return on capital employed (%)	60	40	36	10	47
Net debt/equity ratio (%)[4]	–	–	–	–	–
Net debt/EBITDA ratio[1]	2.4	2.4	1.9	1.9	1.8
Equity ratio (%)	-31	-31	-2	-2	-7
Share of risk capital (%)	10	10	31	31	29
Interest coverage ratio	28	45	18	19	17
Operating cash flow/interest ratio[1]	21	17	21	24	21
Yield	2	1	1	–	2

[1] Excludes the reported after tax accounting gain of MUSD 756.7 on the divestment of a 2.6 percent working interest in the Johan Sverdrup project.

[2] Dividend per share represents the actual paid out dividend per share.

[3] Share price at period end in USD is calculated based on quoted share price in SEK and applicable SEK/USD exchange rate as per period end.

[4] As the equity at 30 September 2019, 31 December 2018 and 30 September 2018 is negative, these ratios have not been calculated.

Relevant Reconciliations of Alternative Performance Measures

EBITDA MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Operating profit	1,588.2	1,047.5	1,102.2	367.2	1,418.7
Minus: gain from sale of assets	-756.7	-756.7	–	–	–
Add: depletion of oil and gas properties	301.6	105.0	341.5	108.8	458.0
Add: exploration costs	84.7	13.8	6.1	0.2	53.2
Add: depreciation of other tangible assets	5.1	1.7	2.0	0.6	2.6
EBITDA	**1,222.9**	**411.3**	1,451.8	476.8	1,932.5

Operating cash flow MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Revenue and other income	2,199.0	1,215.0	1,988.5	604.6	2,640.7
Minus: gain from sale of assets	-756.7	-756.7	–	–	–
Minus: production costs	-118.6	-41.6	-103.8	-31.8	-152.4
Minus: purchase of crude oil from third parties	-84.3	–	-417.2	-92.4	-533.8
Minus: current taxes	-80.5	-36.7	-54.7	-46.0	-90.4
Operating cash flow	**1,158.9**	**380.0**	1,412.8	434.4	1,864.1

Free cash flow MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Cash flows from operating activities	985.3	230.8	1,285.6	478.2	1,718.3
Minus: cash flows from investing activities	132.6	719.7	-795.9	-249.5	-1,055.3
Free cash flow	**1,117.9**	**950.5**	489.7	228.7	663.0

Adjusted net result MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Net result	669.6	519.9	323.9	56.7	225.7
Adjusted for gain or loss from sale of assets	-756.7	-756.7	–	–	–
Adjusted for loan modification gain	–	–	-183.7	–	-183.7
Adjusted for unwinding of loan modification gain	31.4	10.3	15.1	11.4	26.1
Adjusted for foreign currency exchange gain or loss	237.7	272.4	1.2	10.8	164.9
Adjusted for tax effects of above mentioned items	-8.2	-0.5	63.6	-3.8	62.3
Adjusted net result	**173.8**	**45.4**	220.1	75.1	295.3

Net debt MUSD	**1 Jan 2019- 30 Sep 2019 9 months**	**1 Jul 2019- 30 Sep 2019 3 months**	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2018- 31 Dec 2018 12 months
Bank loans	4,150.0	4,150.0	3,645.0	3,645.0	3,465.0
Minus: cash and cash equivalents	-95.1	-95.1	-75.1	-75.1	-66.8
Net debt	**4,054.9**	**4,054.9**	3,569.9	3,569.9	3,398.2

Key Ratio Definitions

Operating cash flow: Revenue and other income less production costs less purchase of crude oil from third parties less current taxes and less gain on sale of assets.

EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortisation): Operating 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.

Free cash flow: Cash flow from operating activities less cash flow from investing activities in accordance with the consolidated statement of cash flow.

Adjusted net result: Net result adjusted for the following items:
- **Gain or loss from sale of assets** is adjusted since the gain or loss does not give an indication of future or periodic performance.
- **Impairment and reversal of impairment** is adjusted since this affects the economics of an asset for the lifetime of that asset, not only the period in which it is impaired or the impairment is reversed.
- **Other items of income and expenses** are adjusted when the impact on net result in the period is not reflective of the company's underlying performance in the period. Such items may be unusual or infrequent transactions but they may also include transactions that are significant which would not necessarily qualify as either unusual or infrequent.
- **Foreign currency exchange gain or loss** is adjusted since the gain or loss does not give an indication of future or periodic performance as currency exchange rates change between periods.
- **Tax effects** of the above mentioned adjustments to net result

Net debt: Bank loan less cash and cash equivalents.

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

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

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

Free cash flow per share: Free 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 any dilution effect.

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

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

Dividend per share: paid out dividends per share 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 any dilution effect.

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

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

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

Net debt/EBITDA ratio: Bank loan less cash and cash equivalents divided by EBITDA of the last four quarters.

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

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

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

Operating cash flow/interest ratio: Operating cash flow divided by the interest expense for the period.

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

Financial Information

The Company will publish the following reports:

- The year end report (January – December 2019) will be published on 31 January 2020.
- The three month report (January – March 2020) will be published on 30 April 2020.
- The six month report (January – June 2020) will be published on 29 July 2020.

The AGM will be held on 31 March 2020 in Stockholm, Sweden.

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

EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
CHF	Swiss franc
EUR	Euro
NOK	Norwegian Krone
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

This information is information that Lundin Petroleum AB is required to make public pursuant to the Securities Markets Act. The information was submitted for publication, through the contact persons set out above, at 07.30 CET on 31 October 2019.

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 Lundin Petroleum'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 Lundin Petroleum 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 Lundin Petroleum’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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