Lundin Petroleum

Q4

YEAR END REPORT 2019

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

- Strong financial performance with record free cash flow generation of MUSD 1,271.7, of which MUSD 312.7 relates to organic free cash flow and MUSD 959.0 relates to the sale of 2.6 percent working interest in Johan Sverdrup
- Board of Directors propose 2019 dividend of USD 1.80 per share corresponding to MUSD 511
- 2019 production averaged 93.3 Mboepd above mid-point of upgraded guidance and at year end production was over 150 Mboepd
- Operating cost of USD 4.03 per boe, below USD 4.25 per boe guidance for the year
- Johan Sverdrup producing around 350 Mbopd gross at year end 2019, 80 percent of Phase 1 plateau rate
- Completion of 2.6 percent sale of Johan Sverdrup and 16 percent share redemption with Equinor during 2019
- Launch of Decarbonisation Strategy targeting carbon neutrality in its exploration and production activities by 2030
- Board of Directors proposes to rename the Company to Lundin Energy

Financial summary

	1 Jan 2019- 31 Dec 2019 12 months	1 Oct 2019- 31 Dec 2019 3 months	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Production in Mboepd	**93.3**	**135.1**	81.1	82.1
Revenue and other income in MUSD	**2,948.7**	**749.7**	2,640.7	652.2
EBITDA in MUSD[1]	**1,918.4**	**695.5**	1,932.5	480.7
Per share in USD[1]	*6.07*	*2.45*	*5.71*	*1.42*
Free cash flow in MUSD	**1,271.7**	**153.8**	663.0	173.3
Per share in USD	*4.03*	*0.54*	*1.96*	*0.51*
Net result in MUSD	**824.9**	**155.3**	225.7	-98.2
Per share in USD	*2.61*	*0.56*	*0.67*	*-0.29*
Adjusted net result in MUSD	**252.7**	**78.9**	295.3	75.2
Per share in USD	*0.80*	*0.28*	*0.87*	*0.22*
Net debt in MUSD	**4,006.7**	**4,006.7**	3,398.2	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:

“2019 has been one of the most transformational periods in the Company’s development, which ended with a record high exit production rate at over 150 Mboepd. Alongside this we have not only transformed what we are producing, we have also focused on how we produce oil and gas in the most sustainable and efficient manner. Such ambition has been formalised through our Decarbonisation Strategy, which targets carbon neutrality by 2030.

“The early startup of Johan Sverdrup Phase 1 in October 2019, was a significant milestone for our business and has firmly laid the foundations for a period of sustainable and efficient production growth well into the next decade. The field has since ramped up quickly and ahead of expectations and at year end was producing around 350 Mbopd gross, which is about 80 percent of the Phase 1 facilities capacity of 440 Mbopd. I would like to thank our teams, as well as the operator Equinor, for executing such a good project; to be achieving first oil on a development of this scale, two months early and significantly under budget, adds real value to our shareholders and is a testament to the hard work of everyone involved.

“Our key Edvard Grieg field continued to exceed expectations with operating efficiency ahead of guidance at 98 percent. This achievement is underpinned by continued reservoir outperformance and limited water production, which alongside the infill drilling programme scheduled for 2020, has enabled us to lift gross ultimate reserves to 300 MMboe. This field has consistently delivered above expectations for us and I am confident this performance will continue in the future, especially as we see more near-field resources being derisked through our ongoing drilling programme.

“Financially we have had another very strong period of free cash flow generation, driven by the sale of 2.6% of Johan Sverdrup, higher production and a cost base which we have continued to maintain at industry leading low levels of USD 4.03 per boe. This coupled with the share redemption from Equinor during the year, has driven our earnings per share and I am glad to note the Board is recommending a 22 percent increased dividend of USD 1.80 per share (in total MUSD 511), clearly demonstrating our focus on driving shareholder returns.

“With the sanction of the full electrification of Edvard Grieg, being developed together with the Johan Sverdrup Phase 2 project, our ambition to produce some of the lowest carbon intensity barrels in the world is closer to being realised. This will result in a significant reduction in CO_2 emissions from the Edvard Grieg Area to below 1 kg per boe by the end of 2022. During the year and in line with the Decarbonisation Strategy, we also started to execute the plan to fully replace all Lundin Petroleum net power usage on both the Edvard Grieg and Johan Sverdrup fields by 2022, through direct investment in profitable renewable projects. These projects will also provide a natural hedge to the electricity price fluctuation, which will represent a significant element of field operating costs. Also announced in January 2020, the Board proposed to change the name of the Company to Lundin Energy in accordance with our Decarbonisation Strategy and our aim to continue to play an important part in the future energy mix.

“2020 is set to be another busy year for Lundin Petroleum across the full spectrum of our operations and we have another very active exploration and appraisal programme with ten wells across our portfolio in Norway, targeting over 650 MMboe of net unrisked resources. I would like to thank all stakeholders for their support during the year and I very much look forward to reporting our progress in 2020.”

For definitions and abbreviations, see pages 32 and 34.

OPERATIONAL REVIEW

All the reported numbers and updates in the operational review relate to the financial year ended 31 December 2019 unless otherwise specified.

Norway

Reserves and Resources

Lundin Petroleum has 693 million barrels of oil equivalent (MMboe) of proved plus probable net reserves and 858 MMboe of proved plus probable plus possible net reserves as at 31 December 2019 as certified by an independent third party. Lundin Petroleum has additional oil and gas resources which classify as contingent resources and the best estimate contingent resources net to Lundin Petroleum amounted to 185 MMboe as at 31 December 2019. The proved plus probable reserves replacement ratio for 2019 was 150 percent.

Production

Production was 93.3 thousand barrels of oil equivalent per day (Mboepd) (compared to 81.1 Mboepd for 2018) which was above the mid-point of the updated guidance for the year of between 90 and 95 Mboepd, and 10 percent above the mid-point of the original production guidance of between 75 and 95 Mboepd. This result is due to early start-up and quick ramp-up at the Johan Sverdrup field as well as continued strong performance at both the Edvard Grieg field and the Alvheim Area. As a result of the quick ramp-up of Johan Sverdrup, production at year end 2019 was over 150 Mboepd.

Operating cost, including netting off tariff income, was USD 4.03 per boe, which is 5 percent below guidance of USD 4.25 per boe. This result is due to higher production volumes.

Production in Mboepd	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**
Norway				
Crude oil	83.5	123.4	71.9	73.5
Gas	9.8	11.7	9.2	8.6
Total production	**93.3**	**135.1**	81.1	82.1

Production in Mboepd	WI[1]	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 30 Dec 2019 3 months**	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 30 Dec 2018 3 months**
Johan Sverdrup	20%	14.0	55.5	–	–
Edvard Grieg	65%	63.7	63.7	63.6	65.6
Ivar Aasen	1.385%	0.8	0.8	0.9	0.8
Alvheim	15%	9.1	8.4	9.3	10.1
Volund	35%	4.8	4.9	6.5	5.2
Bøyla	15%	0.9	1.7	0.7	0.4
Gaupe	40%	-	-	0.1	–
		93.3	**135.1**	81.1	82.1

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

Production from Johan Sverdrup Phase 1 commenced on 5 October 2019, which was at the front of the guidance range for first oil. Production has since ramped up quickly and ahead of expectations from the eight pre-drilled production wells and as at year end 2019 the field was producing around 350 thousands of barrels of oil per day (Mbopd) gross, which is about 80 percent of the Phase 1 facilities capacity of 440 Mbopd. Initial reservoir performance is excellent and well productivities are above expectations. It will require the drilling of two new production wells to achieve Phase 1 plateau, the first of these commenced in January 2020 with the second expected on stream by the summer of 2020. The twelve pre-drilled water injection wells have been commissioned and water injection levels are more than supporting production offtake from the reservoir. The facilities have performed to a high standard, providing a production efficiency during the ramp-up phase above expectations at 94 percent. Operating costs for the Johan Sverdrup field were USD 2.40 per boe.

Production from the Edvard Grieg field was slightly ahead of forecast, supported by production efficiency ahead of guidance at 98 percent. Reservoir performance continues to exceed expectations; with limited water production and total well potential significantly higher than available facilities capacity. A three-well infill drilling programme planned to commence in 2020 has been sanctioned, providing increased reserves of 18 MMboe gross and taking the gross field ultimate proved plus probable reserves to 300 MMboe including historical production. The Rowan Viking jack-up rig, used to drill all the existing development wells has been contracted for the infill programme. Based on the field performance 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 at least 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 costs for the Edvard Grieg field, including netting off tariff income, were USD 4.18 per boe.

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 Edvard Grieg 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 boe, 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 in line with forecast. Two infill wells have been drilled during 2019, which are both producing in line with expectations.

Production from the Alvheim Area, consisting of the Alvheim, Volund and Bøyla fields, was slightly ahead of forecast. Production efficiency for the Alvheim FPSO was ahead of expectations at 97 percent. Two production wells came on stream during 2019, 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 costs for the Alvheim Area were USD 5.79 per boe.

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 in 2019 was MUSD 672 which is eight percent below the updated guidance of MUSD 730 as a result of costs being phased into 2020 for the Company's key projects.

Johan Sverdrup

The Johan Sverdrup Phase 1 project has been developed as a field centre of four platforms - drilling, processing, living quarters and riser platform. Phase 1 of the project 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). Less than ten percent of the current Phase 1 capital estimate remains to be spent on final completion of the production facilities and on fifteen new Phase 1 platform development wells, to be drilled over the period from the first quarter of 2020 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 of 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 boe.

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 over 20 percent complete.

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 boe, about 20 times less than the world average. Post Phase 1 plateau, operating costs will be below USD 2 per boe.

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 of 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 boe. 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 20 percent complete and the Rolvsnes EWT project over 35 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
PL894[1]	Wintershall DEA	10%	Balderbrå	January 2020	Ongoing

[1] subject to closing of deal with Wintershall DEA

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 appraisal well was drilled 1 km west of the discovery well in the downdip Outer Wedge area, making an oil discovery. Other segments of Lille Prinsen are being evaluated for further delineation.

Following the extended well test on the Alta discovery in 2018 and the acquisition of a new 3D seismic (Topseis), the contingent resource estimate for the Alta discovery has been adjusted downwards. A standalone development of the Alta and nearby Gohta discoveries is no longer considered to be commercial, and a subsea tie-back development to either Johan Castberg or another future host development in the area is considered the most viable option. Lundin Petroleum is drilling several large prospects in the Loppa High Area in 2020, which if successful could change the dynamic of commercial options for this area.

In January 2020, drilling commenced on the Balderbrå appraisal well in PL894, an emerging area of the Norwegian Sea with material gas prospectivity. Balderbrå is estimated to contain gross resources of 110 MMboe in Cretaceous sandstone reservoirs and the multi-branch appraisal well is aimed at further delineating the 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
PL896	Wintershall DEA	30%	Toutatis	November 2019	Oil Discovery
PL917	ConocoPhillips	20%	Enniberg	November 2019	Oil & Gas Discovery
PL820S	MOL	40%	Evra/Iving	November 2019	Ongoing
PL917	ConocopPhilips	20%	Hasselbaink	January 2020	Ongoing

Fifteen exploration wells were completed in 2019 yielding seven oil and gas discoveries and adding net resources of between 10 and 50 MMboe. Exploration and appraisal expenditure in 2019 was MUSD 298.

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. 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.

In November 2019, the Toutatis prospect in PL896 in the Norwegian Sea was drilled and made a minor non-commercial oil and gas discovery.

In November 2019, drilling started on the Evra/Iving prospects in PL820S, located east of Alvheim in the North Sea. The dual target well is testing the injectite sandstone reservoir of the Evra prospect and further below, the Jurassic/Triassic reservoirs of the Iving prospect.

In January 2020, the Enniberg prospect in PL917 east of the Alvheim Area in the North Sea was drilled and made a minor non-commercial oil and gas discovery. Following which drilling commenced on the Hasselbaink prospect in the same block, which is testing an Eocene injectite reservoir target with estimated gross unrisked prospective resources of 45 MMboe.

Decarbonisation Strategy

In January 2020, Lundin Petroleum announced its Decarbonisation Strategy with the target to become carbon neutral in its exploration and production activities by 2030. The Company currently has industry leading low carbon emissions with average net carbon intensity for all assets of approximately 5kg CO_2 per boe for 2019. This performance is set to improve further as Johan Sverdrup is already fully electrified from shore and Edvard Grieg is being fully electrified as part of the recently announced Utsira High Area power solution. This will reduce the average net carbon intensity from the Company's producing assets to below 2 kg CO_2 per boe from 2023, which is approximately one-tenth the world average. Additionally, from 2018 the Company has offset the emissions associated with all air travel, including helicopter transport, used in its operations with natural carbon capture.

With the electrification of the Utsira High Area, 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 (estimated at about two thirds of the total electricity usage). In order to replace the Company's net electricity usage at Johan Sverdrup and subsequently Edvard Grieg, direct and profitable investment in renewable energy will be undertaken.

In October 2019, Lundin Petroleum signed an agreement with Sognekraft AS to acquire a 50 percent non-operated interest in the Leikanger hydropower project, in mid-west 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. The investment to Lundin Petroleum, including the acquisition cost, is approximately MUSD 60 over the three year period 2019 to 2021 and the project will be free cash flow positive from 2022. The completion of the transaction remains subject to customary closing conditions, expected to occur in early 2020.

In January 2020, Lundin Petroleum concluded a transaction with OX2 AB (OX2) to acquire a 100 percent interest in the Metsälamminkangas (MLK) wind farm project, in mid Finland. MLK will produce around 400 GWh per annum gross, once it is fully operational in 2022, from 24 onshore wind turbines. The MLK operations will be managed by OX2. The investment, including the acquisition cost, is approximately MUSD 200 gross over 2020 to 2021 and the project will be free cash flow positive from 2022. It is Lundin Petroleum's intention to farm-down 50% of the 100% acquired MLK interest.

The Leikanger and MLK renewable power projects together, (after the intended farm-down) will replace around 60% of the Company's net electricity usage from 2023 with low carbon sources. It is Lundin Petroleum's strategy to fully replace all net electricity usage for power from shore with further direct investments in renewable energy power generation. The projects will also provide a natural hedge to the electricity price fluctuation; the electricity usage of Johan Sverdrup represents approximately 15 percent of the total field operating costs and for Edvard Grieg, it will be approximately 10 percent.

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 increased the Company's working interest to 40 percent in PL820S and to 30 percent in PL896.

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 December 2019, Lundin Petroleum entered into a sales and purchase agreement with Wintershall DEA involving the acquisition of a 10 percent working interest in PL894, which includes the Balderbrå gas discovery and a 5 percent working interest in PL533 and PL533B. The transaction also includes options to acquire working interests in several other exploration licenses in the Vøring Basin where PL894 is located. The transaction is subject to customary government approvals and is expected to complete in the first quarter of 2020.

In December 2019, Lundin Petroleum entered into a sales and purchase agreement with Neptune Energy Norge AS involving the acquisition of a 20 percent working interest in PL886 and PL886B. The transaction increased the Company's working interest to 60 percent in PL886 and PL886B. The transaction is subject to customary government approvals and is expected to complete in the first quarter of 2020.

In January 2020, the Company was awarded 12 licences in the 2019 APA licensing round, of which seven are as operator.

Currently the Company holds 90 licences in Norway, which is an increase of approximately 35 percent from the beginning of 2019.

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. 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 0.6 per million hours worked. There were no material safety or environmental incidents.

FINANCIAL REVIEW

Result

The operating profit for the financial year amounted to MUSD 1,970.7 (MUSD 1,418.7) 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 year excluding this accounting gain amounted to MUSD 1,214.0 with the decrease compared to the comparative period mainly driven by lower oil prices and higher expensed exploration costs and impairment charges somewhat offset by higher production volumes during the financial year.

The net result for the year amounted to MUSD 824.9 (MUSD 225.7) representing earnings per share of USD 2.61 (USD 0.67). 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 financial year, impairment charges of MUSD 128.3, a foreign currency exchange loss of MUSD 131.7 (MUSD 164.9) 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. 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 and better reflects the net result generated by the Company's operational performance for the financial year. Adjusted net result for the year amounted to MUSD 252.7 (MUSD 295.3) representing adjusted earnings per share of USD 0.80 (USD 0.87). The decrease compared to the comparative period was mainly driven by the lower adjusted operating profit.

Earnings before interest, tax, depletion and amortisation (EBITDA) for the year amounted to MUSD 1,918.4 (MUSD 1,932.5) representing EBITDA per share of USD 6.07 (USD 5.71) with the increase on a per share basis compared to the comparative period mainly caused by the redemption of 16 percent of the outstanding shares in August 2019. Operating cash flow for the year amounted to MUSD 1,537.1 (MUSD 1,864.1) representing operating cash flow per share of USD 4.87 (USD 5.51) with the decrease compared to the comparative period impacted by a higher current tax charge as Special Petroleum Tax losses were fully utilized during the fourth quarter of 2019. Free cash flow for the year amounted to MUSD 1,271.7 (MUSD 663.0) representing free cash flow per share of USD 4.03 (USD 1.96) 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. Organic free cash flow for the year which excludes the cash inflow from the sale of 2.6 percent of Johan Sverdrup amounted to MUSD 312.7 and was also impacted by higher paid taxes and increased trade receivables as a result of Johan Sverdrup coming on stream in October 2019.

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

In October 2019, Lundin Petroleum signed an agreement with Sognekraft AS to acquire a 50 percent non-operated interest in the Leikanger hydropower project, in mid-west 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. The investment to Lundin Petroleum, including the acquisition cost, is approximately MUSD 60 over the three year period 2019 to 2021 and the project will be free cash flow positive from 2022. The completion of the transaction remains subject to customary closing conditions, expected to occur in early 2020.

Revenue and other income

Revenue and other income for the year amounted to MUSD 2,948.7 (MUSD 2,640.7) and was comprised of net sales of oil and gas, gain from sale of 2.6 percent of Johan Svedrup and other revenue as detailed in Note 1.

Net sales of oil and gas for the year amounted to MUSD 2,158.6 (MUSD 2,607.9). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 61.00 (USD 67.89) and is detailed in the following table. The average Dated Brent price for the year amounted to USD 64.21 (USD 71.31) per barrel.

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

Sales from own production Average price per boe expressed in USD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Crude oil sales				
– Quantity in Mboe	29,769.7	10,730.7	26,834.7	7,237.5
– *Average price per bbl*	*65.16*	*64.93*	*69.97*	*66.42*
Gas and NGL sales				
– Quantity in Mboe	4,235.7	1,455.8	3,682.0	876.4
– *Average price per boe*	*31.77*	*29.93*	*52.74*	*53.50*
Total sales				
– Quantity in Mboe	**34,005.4**	**12,186.2**	30,516.7	8,113.9
– Average price per boe	***61.00***	***60.75***	*67.89*	*65.03*

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

Net sales of crude oil from third party activities for the year amounted to MUSD 84.3 (MUSD 536.1) and consisted of Grane Blend crude oil purchased from outside the Group by Lundin Petroleum Marketing SA and sold to the market. Revenue from sale of oil and gas are recognised when control of the products is transferred to the customer.

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 8. Other income for the year amounted to MUSD 33.4 (MUSD 32.8) and mainly included tariff income of MUSD 27.2 (MUSD 29.4) 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 year amounted to MUSD 164.8 (MUSD 152.4) 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- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Cost of operations				
– In MUSD	118.1	36.2	102.5	28.5
– In USD per boe	*3.47*	*2.91*	3.46	3.78
Tariff and transportation expenses				
– In MUSD	46.3	15.6	35.2	9.4
– In USD per boe	*1.36*	*1.25*	*1.19*	*1.24*
Operating costs				
– In MUSD	**164.4**	**51.8**	137.7	37.9
–In USD per boe[1]	***4.83***	***4.16***	4.65	5.02
Change in under/over lift position				
– In MUSD	-0.9	-3.5	7.0	9.0
– In USD per boe	*-0.03*	*-0.28*	*0.24*	*1.19*
Change in inventory position				
– In MUSD	-2.8	-3.1	0.6	0.0
– In USD per boe	*-0.08*	*-0.25*	*0.02*	*0.00*
Other				
– In MUSD	4.1	1.0	7.1	1.7
– In USD per boe	*0.12*	*0.08*	*0.24*	*0.23*
Production costs				
– In MUSD	**164.8**	**46.2**	152.4	48.6
–In USD per boe	***4.84***	***3.71***	*5.15*	*6.44*

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 year of USD 4.83 (USD 4.65) per barrel is reduced to USD 4.03 (USD 3.66) when tariff income is netted off. The operating cost for the fourth quarter of USD 4.16 (USD 5.02) per barrel is reduced to USD 3.54 (USD 4.14) when tariff income is netted off.

The total cost of operations for the year amounted to MUSD 118.1 (MUSD 102.5) and the total cost of operations excluding operational projects amounted to MUSD 108.6 (MUSD 93.0). The increase compared to the comparative period related to the start up of production from the Johan Sverdrup field in October 2019 in combination with 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 year amounted to USD 3.47 (USD 3.46) including operational projects and USD 3.19 (USD 3.14) excluding operational projects. The cost of operations per barrel for the fourth quarter amounted to USD 2.91 (USD 3.78) with the reduction compared to the comparative period caused by the start up of production from the Johan Sverdrup field in October 2019.

Tariff and transportation expenses for the year amounted to MUSD 46.3 (MUSD 35.2) or USD 1.36 (USD 1.19) per barrel. The increase compared to the comparative period is driven by the start up of production from the Johan Sverdrup field, higher pipeline tariff rates and freight costs for crude oil sales in relation to some cargoes being sold on a CFR basis during the year.

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 -0.9 (MUSD 7.0) in the year 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- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Production volumes	93.3	135.1	81.1	82.1
Johan Sverdrup inventory movements	-0.7	-2.7	—	—
Production volumes excluding inventory movements	92.6	132.4	81.1	82.1
Sales volumes from own production	93.2	132.5	83.6	88.2
Change in overlift position	**-0.6**	**-0.1**	-2.5	-6.1

Other costs for the year amounted to MUSD 4.1 (MUSD 7.1) and related to the business interruption insurance.

Depletion and decommissioning costs
Depletion and decommissioning costs for the year amounted to MUSD 443.8 (MUSD 458.0) at an average rate of USD 13.03 (USD 15.46) per barrel and are detailed in Note 3. The lower depletion costs for the year compared to the comparative period is due to the start up of production from the Johan Sverdrup field in October 2019 at a lower depletion rate per barrel, what resulted in lower depletion costs for the year although production volumes increased. The depletion costs are further positively impacted by a lower depletion rate per barrel in USD terms as the depletion rate per barrel is calculated in Norwegian Kroner with the Norwegian Kroner having weakened against the USD compared to prior year.

Exploration costs
Exploration costs expensed in the income statement for the year amounted to MUSD 125.6 (MUSD 53.2) 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 when facts and circumstances suggest that the carrying value of an exploration and evaluation asset may exceed its recoverable amount.

Impairment costs of oil and gas properties
Impairment costs charged to the income statement for the year amounted to MUSD 128.3 (MUSD —) and related to certain licenses in the Barents Sea of which future economic development is considered uncertain. A non-cash pre-tax impairment charge of MUSD 128.3 was recognised with an offsetting MUSD 101.3 deferred tax credit recognised in the income statement, yielding a net after tax charge of MUSD 27.0.

Purchase of crude oil from third parties
Purchase of crude oil from third parties for the year amounted to MUSD 84.3 (MUSD 533.8) 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 year amounted to MUSD 31.2 (MUSD 24.6) which included a charge of MUSD 4.6 (MUSD 3.9) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section on page 14. Fixed asset depreciation expenses for the year amounted to MUSD 6.7 (MUSD 2.6) 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 financial year.

Finance income
Finance income for the year amounted to MUSD 27.5 (MUSD 192.2) 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 25.7 (MUSD 3.5).

Finance costs
Finance costs for the year amounted to MUSD 322.5 (MUSD 345.4) and are detailed in Note 5.

The net foreign currency exchange loss for the year amounted to MUSD 131.7 (MUSD 164.9). 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 is exposed to exchange rate fluctuations relating to the relationship between US Dollar and other currencies. Lundin Petroleum has entered into derivative financial instruments to address this exposure for exchange rate fluctuations for capital expenditure amounts, Corporate and Special Petroleum Tax amounts and funding requirements for the share redemption. For the year, the net realised exchange loss on these settled foreign exchange instruments amounted to MUSD 60.9 (gain of MUSD 5.2).

The US Dollar strengthened with 2 percent against the Euro during the year 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 year, generating a net foreign currency exchange gain on an intercompany loan balance denominated in Norwegian Krone.

Interest expenses for the year amounted to MUSD 93.4 (MUSD 88.7) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 85.7 (MUSD 87.6) associated with the funding of the Norwegian development projects was capitalised in the year. The total interest expense for the year increased slightly compared to the comparative period.

The amortisation of the deferred financing fees for the year amounted to MUSD 19.7 (MUSD 17.8) 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 year amounted to MUSD 10.9 (MUSD 13.0) and related mainly to the lower margin for commitment fees as agreed through the amendment of the facility effective as of 1 June 2018 in combination with a higher outstanding loan under the reserve-based lending facility following the share redemption in August 2019 what resulted in lower commitment fees.

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 year amounted to MUSD 41.5 (MUSD 26.1) 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 year amounted to MUSD -1.8 (MUSD -1.3) and related to the share in the result of the investment in Mintley Caspian Ltd.

Tax
The overall tax charge for the year amounted to MUSD 849.0 (MUSD 1,038.5) and is detailed in Note 6.

The current tax charge for the year amounted to MUSD 405.8 (MUSD 90.4) and mainly related to Norway. The current tax charge for Norway related to both Corporate Tax and Special Petroleum Tax (SPT). The SPT tax losses were fully utilized during the fourth quarter of 2019 which resulted in increased current tax charges. The paid tax installments in Norway during the year amounted to MUSD 131.7 which has in combination with the current tax charge for the year resulted in an increase in current tax liabilities compared to the comparative period.

The deferred tax charge for the year amounted to MUSD 443.2 (MUSD 948.1) and related to Norway. A 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 year 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 5,473.2 (MUSD 5,341.1) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Norway	672.3	174.3	701.9	151.0
Development expenditure	**672.3**	**174.3**	701.9	151.0

Development expenditure of MUSD 672.3 (MUSD 701.9) was incurred in Norway during the year, primarily on the Johan Sverdrup field. In addition an amount of MUSD 85.7 (MUSD 87.6) of interest was capitalised.

Exploration and appraisal expenditure in MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Norway	298.4	62.1	310.6	85.4
Exploration and appraisal expenditure	**298.4**	**62.1**	310.6	85.4

Exploration and appraisal expenditure of MUSD 298.4 (MUSD 310.6) was incurred in Norway during the year, primarily for the exploration and appraisal wells as summarized on page 5.

Other tangible fixed assets amounted to MUSD 49.4 (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 35.9 (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 14.3 (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 12.4 (MUSD —).

Derivative instruments amounted to MUSD 2.7 (MUSD 2.7) and related to the marked-to-market gain on the outstanding currency hedge contracts due to be settled after twelve months.

Current assets

Inventories amounted to MUSD 40.7 (MUSD 36.5) and included both well supplies and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 349.5 (MUSD 216.6) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 305.1 (MUSD 153.7) with the increase caused by the start up of production from Johan Sverdrup. Underlift amounted to MUSD 2.0 (MUSD 1.9) and was attributable to an underlift position on the producing fields, mainly relating to oil from the Johan Sverdrup field. Joint operations debtors relating to various joint venture receivables amounted to MUSD 11.4 (MUSD 17.0). Prepaid expenses and accrued income amounted to MUSD 23.9 (MUSD 26.9) and represented mainly prepaid operational and insurance expenditure. Other current assets amounted to MUSD 7.1 (MUSD 17.1) with the reduction mainly caused by the receipt during the year of the short term receivable from IPC relating to certain working capital balances following the IPC spin-off.

Derivative instruments amounted to MUSD 11.3 (MUSD 34.0) and related to the marked-to-market gain on the outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Cash and cash equivalents amounted to MUSD 85.3 (MUSD 66.8). Cash balances are mainly held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,888.4 (MUSD 3,262.0) and are detailed in Note 11. Bank loans amounted to MUSD 4,000.0 (MUSD 3,465.0) and related to the long-term portion of the outstanding loan under the reserve-based lending facility with the short-term portion classified as current liabilities. Capitalised financing fees relating to the establishment of the facility amounted to MUSD 37.1 (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 105.6 (MUSD 148.9) and are being amortised over the expected life of the facility. The lease commitments amounted to MUSD 31.1 (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 528.1 (MUSD 489.1) and are detailed in Note 12. The provision for site restoration amounted to MUSD 522.2 (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 and amounted to MUSD 49.2 (MUSD 6.6). The total increase in site restoration reflects the additional liability for the Johan Sverdrup field partly offset by the sale of 2.6 percent of Johan Sverdrup, and expected increases in site restoration costs for the other fields.

Deferred tax liabilities amounted to MUSD 2,412.7 (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 110.8 (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 97.5 (MUSD –) and are detailed in Note 11. Current financial liabilities related to the short-term portion of the outstanding bank loans and lease commitments.

Dividends amounted to MUSD 106.0 (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 177.4 (MUSD 200.9) and are detailed in Note 13. Overlift amounted to MUSD 0.9 (MUSD 1.7) and was attributable to an overlift position in relation to condensate from the Edvard Grieg field. Joint operations creditors and accrued expenses amounted to MUSD 133.6 (MUSD 147.4) and related to activity in Norway. Other accrued expenses amounted to MUSD 16.6 (MUSD 17.6) and other current liabilities amounted to MUSD 8.5 (MUSD 7.6).

Derivative instruments amounted to MUSD 33.2 (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 343.3 (MUSD 70.4) and related mainly to Norway.

Current provisions amounted to MUSD 55.9 (MUSD 12.5) and are detailed in Note 12. The short-term portion of the future decommissioning obligations amounted to MUSD 49.2 (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 6.7 (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 year amounted to MSEK 18,885.5 (MSEK 1,657.8). The net result for the year included MSEK 19,148.4 (MSEK 1,812.4) financial income as a result of received dividends from a subsidiary. The net result excluding received dividends amounted to MSEK -262.9 (MSEK -154.6).

The net result for the year included general and administrative expenses of MSEK 248.1 (MSEK 180.9) and net finance costs of MSEK 33.7 (finance income of MSEK 5.3) 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 year, 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 296.2).

The Group has sold oil and related products to the Equinor group on an arm's-length basis amounting to MUSD 107.3 (MUSD 879.5).

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 year.

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. The size of the committed facility will reduce from USD 5.0 billion to USD 4.75 billion as per 1 July 2020 and to USD 4.0 billion as per 1 January 2021.

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

In January 2020, Lundin Petroleum concluded a transaction with OX2 AB (OX2)to acquire a 100 percent interest in the Metsälamminkangas (MLK) wind farm project, in mid Finland. MLK will produce around 400 GWh per annum gross, once it is fully operational in 2022, from 24 onshore wind turbines. The MLK operations will be managed by OX2. The investment, including the acquisition cost, is approximately MUSD 200 gross over 2020 to 2021 and the project will be free cash flow positive from 2022. It is Lundin Petroleum's intention to farm-down 50% of the 100% acquired MLK interest.

In January 2020, Lundin Petroleum entered into a revolving credit facility amounting to MUSD 260 for the financing of the renewable power projects with a current interest rate margin over LIBOR of 1.25 percent.

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 year, 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 actual paid out dividend subsequently reduced to MUSD 460.7 following the redemption of 54,461,831 shares in August 2019. The first dividend payment was made on 5 April 2019, the second dividend payment was made on 8 July 2019, the third dividend payment was made on 7 October 2019 and the fourth dividend payment was made on 9 January 2020.

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.

2019 dividend proposal

Lundin Petroleum's objective is to create attractive shareholder returns by investing through the business cycle with capital investments allocated to exploration, development and production assets. The Company's expectation is to create shareholder returns both through share price appreciation and by distributing a sustainable yearly dividend - paid in quarterly instalments and denominated in USD - with the plan of maintaining or increasing the dividend over time in line with the Company's financial performance and being sustainable below an oil price of USD 50 per barrel. The dividend shall be sustainable in the context of allowing the Company to continue to pursue its organic growth strategy and to develop its contingent resources whilst maintaining a conservative gearing ratio and retaining an appropriate liquidity position within its available credit lines.

In accordance with the dividend policy, the Board of Directors will propose to the 2020 Annual General Meeting a dividend for 2019 of USD 1.80 per share, corresponding to USD 511 million (rounded off), to be paid in quarterly instalments of USD 0.45 per share, corresponding to USD 128 million (rounded off). Before payment, each quarterly dividend of USD 0.45 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. The SEK amount per share to be distributed each quarter will be announced in a press release four business days prior to each record date.

The first dividend payment is expected to be paid around 7 April 2020, with an expected record date of 2 April 2020 and expected ex-dividend date of 1 April 2020. The second dividend payment is expected to be paid around 8 July 2020, with an expected record date of 3 July 2020 and expected ex-dividend date of 2 July 2020. The third dividend payment is expected to be paid around 7 October 2020, with an expected record date of 2 October 2020 and an expected ex-dividend date of 1 October 2020. The fourth dividend payment is expected to be paid around 8 January 2021, with an expected record date of 4 January 2021 and an expected ex-dividend date of 30 December 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 2019 dividend has been set to a cap of SEK 9.203 billion (i.e., SEK 2.301 billion per quarter). If the total dividend would exceed the cap of SEK 9.203 billion, the dividend will be automatically adjusted downwards so that the total dividend corresponds to the cap of SEK 9.203 billion.

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 31 December 2019 were 89,508, 143,492 and 188,425 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 31 December 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 31 December 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 31 December 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 derivative financial instruments to address its exposure for exchange rate fluctuations for capital expenditure amounts relating to its committed field development projects and Corporate and Special Petroleum Tax amounts. At 31 December 2019, Lundin Petroleum had outstanding foreign currency contracts as summarised below:

Buy	Sell	Average contractual Exchange rate	Settlement period
MNOK 7,304.0	MUSD 842.7	NOK 8.67:USD 1	Jan 2020 – Dec 2020
MNOK 2,470.0	MUSD 310.0	NOK 7.97:USD 1	Jan 2021 – Dec 2021
MNOK 1,430.0	MUSD 183.4	NOK 7.80:USD 1	Jan 2022 – Dec 2022
MNOK 530.0	MUSD 64.2	NOK 8.26:USD 1	Jan 2023 – Dec 2023
MNOK 300.0	MUSD 33.0	NOK 9.09:USD 1	Jan 2024 – Dec 2024

Lundin Petroleum entered into interest rate hedge contracts and at 31 December 2019 had outstanding interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR average rate per annum	Settlement period
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 year, the following currency exchange rates have been used.

	31 Dec 2019		31 Dec 2018	
	Average	Period end	Average	Period end
1 USD equals NOK	8.8003	8.7803	8.1329	8.6885
1 USD equals Euro	0.8932	0.8902	0.8464	0.8734
1 USD equals SEK	9.4581	9.2993	8.6921	8.9562

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2019- 31 Dec 2019 12 months	1 Oct 2019- 31 Dec 2019 3 months	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Revenue and other income	1				
Revenue		2,158.6	740.3	2,607.9	644.6
Gain from sale of assets		756.7	–	–	–
Other income		33.4	9.4	32.8	7.6
		2,948.7	**749.7**	2,640.7	652.2
Cost of sales					
Production costs	2	-164.8	-46.2	-152.4	-48.6
Depletion and decommissioning costs		-443.8	-142.2	-458.0	-116.5
Exploration costs		-125.6	-40.9	-53.2	-47.1
Impairment costs of oil and gas properties		-128.3	-128.3	–	–
Purchase of crude oil from third parties		-84.3	–	-533.8	-116.6
Gross profit	3	**2,001.9**	**392.1**	1,443.3	323.4
General, administration and depreciation expenses		-31.2	-9.6	-24.6	-6.9
Operating profit		**1,970.7**	**382.5**	1,418.7	316.5
Net financial items					
Finance income	4	27.5	3.7	192.2	4.0
Finance costs	5	-322.5	44.1	-345.4	-207.1
		-295.0	**47.8**	-153.2	-203.1
Share in result of associated company		-1.8	-0.5	-1.3	-0.7
Profit before tax		**1,673.9**	**429.8**	1,264.2	112.7
Income tax	6	-849.0	-274.5	-1,038.5	-210.9
Net result		**824.9**	**155.3**	225.7	-98.2
Attributable to:					
Shareholders of the Parent Company		824.9	155.3	225.7	-98.2
Non-controlling interest		–	–	–	–
		824.9	**155.3**	225.7	-98.2
Earnings per share – USD		2.61	0.56	0.67	-0.29
Earnings per share fully diluted – USD		2.61	0.56	0.66	-0.29
Adjusted earnings per share – USD		0.80	0.28	0.87	0.22
Adjusted earnings per share fully diluted – USD		0.80	0.28	0.87	0.22

Consolidated Statement of Comprehensive Income

Expressed in MUSD	1 Jan 2019- 31 Dec 2019 12 months	1 Oct 2019- 31 Dec 2019 3 months	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Net result	**824.9**	**155.3**	225.7	-98.2
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	29.0	-45.1	1.5	-14.4
Cash flow hedges	-82.5	89.6	-74.1	-118.6
Other comprehensive income, net of tax	**-53.5**	**44.5**	-72.6	-133.0
Total comprehensive income	**771.4**	**199.8**	153.1	-231.2
Attributable to:				
Shareholders of the Parent Company	771.4	199.8	153.1	-231.2
Non-controlling interest	—	—	—	—
	771.4	**199.8**	153.1	-231.2

Consolidated Balance Sheet

Expressed in MUSD	Note	31 December 2019	31 December 2018
ASSETS			
Non-current assets			
Oil and gas properties	7	5,473.2	5,341.1
Other tangible fixed assets	8	49.4	13.6
Goodwill		128.1	128.1
Financial assets	9	14.3	0.4
Derivative instruments	14	2.7	2.7
Total non-current assets		**5,667.7**	5,485.9
Current assets			
Inventories		40.7	36.5
Trade and other receivables	10	349.5	216.6
Derivative instruments	14	11.3	34.0
Cash and cash equivalents		85.3	66.8
Total current assets		**486.8**	353.9
TOTAL ASSETS		**6,154.5**	5,839.8
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		**-1,598.8**	-383.8
Liabilities			
Non-current liabilities			
Financial liabilities	11	3,888.4	3,262.0
Provisions	12	528.1	489.1
Deferred tax liabilities		2,412.7	2,103.8
Derivative instruments	14	110.8	64.9
Total non-current liabilities		**6,940.0**	5,919.8
Current liabilities			
Financial liabilities	11	97.5	–
Dividends		106.0	–
Trade and other payables	13	177.4	200.9
Derivative instruments	14	33.2	20.0
Current tax liabilities		343.3	70.4
Provisions	12	55.9	12.5
Total current liabilities		**813.3**	303.8
Total liabilities		**7,753.3**	6,223.6
TOTAL EQUITY AND LIABILITIES		**6,154.5**	5,839.8

Consolidated Statement of Cash Flows

Expressed in MUSD	1 Jan 2019-31 Dec 2019 12 months	1 Oct 2019-31 Dec 2019 3 months	1 Jan 2018-31 Dec 2018 12 months	1 Oct 2018-31 Dec 2018 3 months
Cash flows from operating activities				
Net result	824.9	155.3	225.7	-98.2
Adjustments for:				
Gain from sale of assets	-756.7	—	—	—
Exploration costs	125.6	40.9	53.2	47.1
Depletion, depreciation and amortisation	450.5	143.9	460.6	117.1
Impairment of oil and gas properties	128.3	128.3	—	—
Current tax	405.8	325.3	90.4	35.7
Deferred tax	443.2	-50.8	948.1	175.2
Long-term incentive plans	14.7	4.6	14.6	0.5
Foreign currency exchange gain/ loss	70.8	-120.5	162.5	161.5
Interest expense	93.4	38.7	88.7	20.0
Loan modification gain	—	—	-183.7	—
Loan modification fees	—	—	17.3	—
Unwinding of loan modification gain	41.5	10.1	26.1	11.0
Amortisation of deferred financing fees	19.7	3.9	17.8	4.3
Other	17.8	4.4	12.8	4.4
Interest received	1.8	0.5	1.1	0.3
Interest paid	-177.4	-59.2	-176.0	-42.9
Income taxes paid / received	-132.7	-97.3	-15.8	-10.0
Changes in working capital	-193.0	-135.2	-25.1	6.7
Total cash flows from operating activities	**1,378.2**	**392.9**	1,718.3	432.7
Cash flows from investing activities				
Investment in oil and gas properties	-1,057.8	-235.9	-1,060.1	-258.4
Investment in other fixed assets	-2.5	-1.1	-3.2	-0.5
Investment in financial assets	-1.5	-1.2	9.3	—
Disposal of fixed assets[1]	959.0	—	—	—
Decommissioning costs paid	-3.7	-0.9	-1.3	-0.5
Total cash flows from investing activities	**-106.5**	**-239.1**	-1,055.3	-259.4
Cash flows from financing activities				
Changes in long-term bank loans	627.0	-58.0	-490.0	-180.0
Changes in lease commitments[2]	-3.4	-0.8	—	—
Financing fees paid	-3.3	—	-17.3	—
Dividends paid	-355.6	-105.1	-153.1	—
Share redemption	-1,517.2	—	—	—
Purchase of own share	—	—	-14.3	—
Total cash flows from financing activities	**-1,252.5**	**-163.9**	-674.7	-180.0
Change in cash and cash equivalents	19.2	-10.1	-11.7	-6.7
Cash and cash equivalents at the beginning of the period	66.8	95.1	71.4	75.1
Currency exchange difference in cash and cash equivalents	-0.7	0.3	7.1	-1.6
Cash and cash equivalents at the end of the period	**85.3**	**85.3**	66.8	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	—	—	225.7	—	225.7
Other comprehensive income	—	-72.6	—	—	-72.6
Total comprehensive income	**—**	**-72.6**	**225.7**	**—**	**153.1**
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	—	—	5.5	—	5.5
Total transactions with owners	**—**	**-35.1**	**5.5**	**-153.1**	**-182.7**
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	—	—	824.9	—	824.9
Other comprehensive income	—	-53.5	—	—	-53.5
Total comprehensive income	**—**	**-53.5**	**824.9**	**—**	**771.4**
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	—	—	5.3	—	5.3
Total transaction with owners	**—**	**-1,490.7**	**5.3**	**-501.0**	**-1,986.4**
At 31 December 2019	**0.5**	**-1,722.8**	**624.5**	**-501.0**	**-1,598.8**

[1] Relates to change in accounting principle for revenue recognition relating to under/overlift balances as mentioned on page 15.

Notes to the Consolidated Financial Statements

Note 1 — Revenue and other income MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Revenue				
Crude oil from own production	1,939.8	696.8	1,877.6	480.7
Crude oil from third party activities	84.3	—	536.1	117.0
Condensate	41.4	17.8	41.8	7.3
Gas	93.1	25.7	152.4	39.6
Sales of oil and gas	**2,158.6**	**740.3**	2,607.9	644.6
Gain from sale of assets	756.7	—	—	—
Other income	33.4	9.4	32.8	7.6
Revenue and other income	**2,948.7**	**749.7**	2,640.7	652.2

Note 2 — Production costs MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Cost of operations	118.1	36.2	102.5	28.5
Tariff and transportation expenses	46.3	15.6	35.2	9.4
Change in under/over lift position	-0.9	-3.5	7.0	9.0
Change in inventory position	-2.8	-3.1	0.6	—
Other	4.1	1.0	7.1	1.7
Production costs	**164.8**	**46.2**	152.4	48.6

Note 3 — Segment information MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Norway				
Crude oil from own production	1,939.8	696.8	1,877.6	480.7
Condensate	41.4	17.8	41.8	7.3
Gas	93.1	25.7	152.4	39.6
Revenue	**2,074.3**	**740.3**	2,071.8	527.6
Gain from sale of assets	756.7	—	—	—
Other income	33.4	9.4	32.8	7.6
Revenue and other income	**2,864.4**	**749.7**	2,104.6	535.2
Production costs	-164.8	-46.2	-152.4	-48.6
Depletion and decommissioning costs	-443.8	-142.2	-458.0	-116.5
Exploration costs	-125.6	-40.9	-53.2	-47.1
Impairment costs of oil and gas properties	-128.3	-128.3	—	—
Gross profit	**2,001.9**	**392.1**	1,441.0	323.0
Other				
Crude oil from third party activities	84.3	—	536.1	117.0
Revenue	**84.3**	**—**	536.1	117.0
Purchase of crude oil from third parties	-84.3	—	-533.8	116.6
Gross profit	**0.0**	**—**	2.3	0.4

Note 3 — Segment information cont. MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Total				
Crude oil from own production	1,939.8	696.8	1,877.6	480.7
Crude oil from third party activities	84.3	—	536.1	117.0
Condensate	41.4	17.8	41.8	7.3
Gas	93.1	25.7	152.4	39.6
Revenue	**2,158.6**	**740.3**	2,607.9	644.6
Gain from sale of assets	756.7	—	—	—
Other income	33.4	9.4	32.8	7.6
Revenue and other income	**2,948.7**	**749.7**	2,640.7	652.2
Production costs	-164.8	-46.2	-152.4	-48.6
Depletion and decommissioning costs	-443.8	-142.2	-458.0	-116.5
Exploration costs	-125.6	-40.9	-53.2	-47.1
Impairment costs of oil and gas properties	-128.3	-128.3	—	—
Purchase of crude oil from third parties	-84.3	—	-533.8	-116.6
Gross profit	**2,001.9**	**392.1**	1,443.3	323.4

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

Note 4 — Finance income MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Loan modification gain	—	—	183.7	—
Interest income	1.8	0.5	1.7	0.6
Gain on interest rate hedge settlement	25.7	3.2	3.5	3.4
Other	—	—	3.3	—
Finance income	**27.5**	**3.7**	192.2	4.0

Note 5 — Finance costs MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Foreign currency exchange loss, net	131.7	-106.0	164.9	163.7
Interest expense	93.4	38.7	88.7	20.0
Unwinding of site restoration discount	17.9	4.5	16.4	4.4
Amortisation of deferred financing fees	19.7	3.9	17.8	4.3
Loan facility commitment fees	10.9	2.0	13.0	3.3
Loan modification fees	—	—	17.3	—
Unwinding of loan modification gain	41.5	10.1	26.1	11.0
Other	7.4	2.7	1.2	0.4
Finance costs	**322.5**	**-44.1**	345.4	207.1

Note 6 — Income tax MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Current tax	405.8	325.3	90.4	35.7
Deferred tax	443.2	-50.8	948.1	175.2
Income tax	**849.0**	**274.5**	1,038.5	210.9

Note 7 — Oil and gas properties

MUSD	**31 Dec 2019**	31 Dec 2018
Norway		
Producing assets	4,065.3	1,759.3
Assets under development	652.2	2,750.1
Capitalised exploration and appraisal expenditure	755.7	831.7
	5,473.2	5,341.1

Note 8 — Other tangible fixed assets

MUSD	**31 Dec 2019**	31 Dec 2018
Right of use assets	35.9	–
Other	13.5	13.6
	49.4	13.6

Note 9 — Financial assets

MUSD	**31 Dec 2019**	31 Dec 2018
Contingent consideration	12.4	–
Other shares and participations	0.3	–
Other	1.6	0.4
	14.3	0.4

Note 10 — Trade and other receivables

MUSD	**31 Dec 2019**	31 Dec 2018
Trade receivables	305.1	153.7
Underlift	2.0	1.9
Joint operations debtors	11.4	17.0
Prepaid expenses and accrued income	23.9	26.9
Other	7.1	17.1
	349.5	216.6

Note 11 — Financial liabilities

MUSD	**31 Dec 2019**	31 Dec 2018
Non-current:		
Bank loans	4,000.0	3,465.0
Capitalised financing fees	-37.1	-54.1
Capitalised loan modification gain	-105.6	-148.9
Lease commitments	31.1	–
	3,888.4	3,262.0
Current:		
Bank loans	92.0	–
Lease commitments	5.5	–
	97.5	–
	3,985.9	3,262.0

Note 12 — Provisions

MUSD	**31 Dec 2019**	31 Dec 2018
Non-current:		
Site restoration	522.2	483.9
Long-term incentive plans	2.7	2.4
Other	3.2	2.8
	528.1	489.1
Current:		
Site restoration	49.2	6.6
Long-term incentive plans	6.7	5.9
	55.9	12.5
	584.0	501.6

Note 13 — Trade and other payables MUSD	31 Dec 2019	31 Dec 2018
Trade payables	17.8	26.6
Overlift	0.9	1.7
Joint operations creditors and accrued expenses	133.6	147.4
Other accrued expenses	16.6	17.6
Other	8.5	7.6
	177.4	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:

31 December 2019 MUSD	Level 1	Level 2	Level 3
Assets			
Contingent consideration	–	–	12.4
Derivative instruments – non-current	–	2.7	–
Derivative instruments – current	–	11.3	–
	–	**14.0**	**12.4**
Liabilities			
Derivative instruments – non-current	–	110.8	–
Derivative instruments – current	–	33.2	–
	–	**144.0**	**–**

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 year.

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

Parent Company Income Statement

Expressed in MSEK	1 Jan 2019-31 Dec 2019 12 months	1 Oct 2019-31 Dec 2019 3 months	1 Jan 2018-31 Dec 2018 12 months	1 Oct 2018-31 Dec 2018 3 months
Revenue	18.9	9.4	21.0	11.8
General and administration expenses	-248.1	-77.6	-180.9	-56.5
Operating loss	**-229.2**	**-68.2**	-159.9	-44.7
Net financial items				
Finance income	19,148.5	-11.3	1,818.1	97.5
Finance costs	-33.8	-0.6	-0.4	–
	19,114.7	**-11.9**	1,817.7	97.5
Profit before tax	**18,885.5**	**-80.1**	1,657.8	52.8
Income tax	–	–	–	–
Net result	**18,885.5**	**-80.1**	1,657.8	52.8

Parent Company Comprehensive Income Statement

Expressed in MSEK	1 Jan 2019-31 Dec 2019 12 months	1 Oct 2019-31 Dec 2019 3 months	1 Jan 2018-31 Dec 2018 12 months	1 Oct 2018-31 Dec 2018 3 months
Net result	**18,885.5**	**-80.1**	1,657.8	52.8
Other comprehensive income	–	–	–	–
Total comprehensive income	**18,885.5**	**-80.1**	1,657.8	52.8
Attributable to:				
Shareholders of the Parent Company	18,885.5	-80.1	1,657.8	52.8
	18,885.5	**-80.1**	1,657.8	52.8

Parent Company Balance Sheet

Expressed in MSEK	**31 December 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	1,107.4	5.4
Cash and cash equivalents	31.7	29.5
Total current assets	**1,139.1**	34.9
TOTAL ASSETS	**56,258.4**	55,154.2
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	55,242.8	55,120.8
Non-current liabilities		
Provisions	1.0	0.7
Total non-current liabilities	**1.0**	0.7
Current liabilities		
Dividends	985.7	–
Other liabilities	28.9	32.7
Total current liabilities	**1,014.6**	32.7
Total liabilities	**1,015.6**	33.4
TOTAL EQUITY AND LIABILITIES	**56,258.4**	55,154.2

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Cash flow from operations				
Net result	18,885.5	-80.1	1,657.8	52.8
Adjustment for non-cash related items	-1,157.9	1,171.5	-4.8	0.2
Changes in working capital	133.0	-68.3	-159.9	-54.4
Total cash flow from operations	**17,860.6**	**1,023.1**	1,493.1	-1.4
Cash flow from investing				
Investments in other fixed assets	-0.1	—	-0.4	-0.3
Total cash flow from investing	**-0.1**	**—**	-0.4	-0.3
Cash flow from financing				
Dividends paid	-3,347.6	-1,025.4	-1,354.1	—
Share redemption	-14,510.3	—	—	—
Purchase of own shares	—	—	-119.5	—
Total cash flow from financing	**-17,857.9**	**-1,025.4**	-1,473.6	—
Change in cash and cash equivalents	2.6	-2.3	19.1	-1.7
Cash and cash equivalents at the beginning of the period	29.5	36.9	4.8	31.6
Currency exchange difference in cash and cash equivalents	-0.4	-2.9	5.6	0.4
Cash and cash equivalents at the end of the period	**31.7**	**31.7**	29.5	29.5

Parent Company Statement of Changes in Equity

Expressed in MSEK	Restricted equity: Share capital	Restricted equity: Statutory reserve	Unrestricted equity: Other reserves	Unrestricted equity: Retained earnings	Unrestricted equity: Dividends	Unrestricted equity: 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	**–**	**–**	**–**	**1,657.8**	**–**	**1,657.8**	**1,657.8**
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 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	**–**	**–**	**–**	**18,885.5**	**–**	**18,885.5**	**18,885.5**
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 31 December 2019	**3.5**	**861.3**	**6,479.7**	**52,537.0**	**-4,638.7**	**54,378.0**	**55,242.8**

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- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Revenue and other income	2,948.7	749.7	2,640.7	652.2
Operating cash flow[1]	1,537.1	378.2	1,864.1	451.3
EBITDA[1]	1,918.4	695.5	1,932.5	480.7
Free cash flow	1,271.7	153.8	663.0	173.3
Net result	824.9	155.3	225.7	-98.2
Adjusted net result	252.7	78.9	295.3	75.2
Net debt	4,006.7	4,006.7	3,398.2	3,398.2
Data per share USD				
Shareholders' equity per share	-5.63	-5.63	-1.13	-1.13
Operating cash flow per share[1]	4.87	1.33	5.51	1.34
EBITDA per share[1]	6.07	2.45	5.71	1.42
Free cash flow per share	4.03	0.54	1.96	0.51
Earnings per share	2.61	0.56	0.67	-0.29
Earnings per share fully diluted	2.61	0.56	0.66	-0.29
Adjusted earnings per share	0.80	0.28	0.87	0.22
Adjusted earnings per share fully diluted	0.80	0.28	0.87	0.22
Dividend per share[2]	1.11	0.37	0.45	–
Number of shares issued at period end	285,924,614	285,924,614	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
Weighted average number of shares for the period	315,833,140	284,051,304	338,592,250	338,513,135
Weighted average number of shares for the period fully diluted	316,551,300	284,531,709	339,513,634	339,078,717
Share price				
Share price at period end in SEK	318.30	318.30	221.40	221.40
Share price at period end in USD[3]	34.23	34.23	24.72	24.72
Key ratios				
Return on equity (%)[4]	–	–	–	–
Return on capital employed (%)	72	14	47	9
Net debt/equity ratio (%)[4]	–	–	–	–
Net debt/EBITDA ratio[1]	2.1	2.1	1.8	1.8
Equity ratio (%)	-26	-26	-7	-7
Share of risk capital (%)	13	13	29	29
Interest coverage ratio	20	9	17	15
Operating cash flow/interest ratio[1]	16	10	21	23
Yield	3	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 31 December 2019 and 31 December 2018 is negative, these ratios have not been calculated.

Relevant Reconciliations of Alternative Performance Measures

EBITDA MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Operating profit	1,970.7	382.5	1,418.7	316.5
Minus: gain from sale of assets	-756.7	—	—	—
Add: depletion of oil and gas properties	443.8	142.2	458.0	116.5
Add: exploration costs	125.6	40.9	53.2	47.1
Add: impairment costs of oil and gas properties	128.3	128.3	—	—
Add: depreciation of other tangible assets	6.7	1.6	2.6	0.6
EBITDA	**1,918.4**	**695.5**	1,932.5	480.7

Operating cash flow MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Revenue and other income	2,948.7	749.7	2,640.7	652.2
Minus: gain from sale of assets	-756.7	—	—	—
Minus: production costs	-164.8	-46.2	-152.4	-48.6
Minus: purchase of crude oil from third parties	-84.3	—	-533.8	-116.6
Minus: current taxes	-405.8	-325.3	-90.4	-35.7
Operating cash flow	**1,537.1**	**378.2**	1,864.1	451.3

Free cash flow MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Cash flows from operating activities	1,378.2	392.9	1,718.3	432.7
Minus: cash flows from investing activities	-106.5	-239.1	-1,055.3	-259.4
Free cash flow	**1,271.7**	**153.8**	663.0	173.3

Adjusted net result MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Net result	824.9	155.3	225.7	-98.2
Adjusted for gain or loss from sale of assets	-756.7	—	—	—
Adjusted for impairment costs of oil and gas properties	128.3	128.3	—	—
Adjusted for loan modification gain	—	—	-183.7	—
Adjusted for unwinding of loan modification gain	41.5	10.1	26.1	11.0
Adjusted for foreign currency exchange gain or loss	131.7	-106.0	164.9	163.7
Adjusted for tax effects of above mentioned items	-117.0	-108.8	62.3	-1.3
Adjusted net result	**252.7**	**78.9**	295.3	75.2

Net debt MUSD	**1 Jan 2019- 31 Dec 2019 12 months**	**1 Oct 2019- 31 Dec 2019 3 months**	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months
Bank loans	4,092.0	4,092.0	3,465.0	3,465.0
Minus: cash and cash equivalents	-85.3	-85.3	-66.8	-66.8
Net debt	**4,006.7**	**4,006.7**	3,398.2	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.

Board Assurance

The Board of Directors and the President and CEO certify that the financial report for the twelve months ended 31 December 2019 gives a fair view of the performance of the business, position and profit or loss of the Company and the Group, and describes the principal risks and uncertainties that the Company and the companies in the Group face.

Stockholm, 31 January 2020

Ian H. Lundin Chairman	Alex Schneiter President and CEO	Peggy Bruzelius
C. Ashley Heppenstall	Lukas H. Lundin	Torstein Sanness
Grace Reksten Skaugen	Jakob Thomasen	Cecilia Vieweg

Financial Information

The Company will publish the following reports:

- 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 nine month report (January — September 2020) will be published on 29 October 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 January 2020.

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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