Third Quarter 2018

QUARTERLY REPORT
FOR AKER BP ASA

SUMMARY OF THE QUARTER

Aker BP (OSE:AKERBP) reports total income of USD 1,000 million and operating profit of USD 548 million for the third quarter 2018. Net profit was USD 125 million and earnings per share were USD 0.35. The company paid a dividend of USD 0.3124 (NOK 2.53) per share in the quarter.

The company's net production in the third quarter was 150.6 (131.9) thousand barrels of oil equivalents per day ("mboepd"). For the first nine months, production was 155.6 mboepd, and the company still expects full-year production to be within the previously communicated range of 155-160 mboepd.

Revenues were positively impacted by increased oil and gas prices. Average realised prices were USD 78 (55) per barrel of oil, and USD 0.30 (0.20) per standard cubic metre ("scm") of natural gas.

Production costs amounted to USD 165 (134) million or USD 11.9 (11.1) per barrel oil equivalents ("boe"). For the first nine months, production cost per boe averaged USD 11.8, and remains in line with the company's estimate of around USD 12 per boe for the full year.

Exploration expenses amounted to USD 94 (64) million. This was driven by three dry exploration wells, as well as seismic acquisitions and field evaluation expenses. The appraisal wells at Gekko and Hanz were successful. The company's estimated exploration spend for 2018 has been revised down to USD 400 million (previously USD 425 million).

Operating profit (EBIT) was USD 548 (219) million, after depreciation of USD 189 (175) million or USD 13.6 (14.5) per boe. Net financial expenses were USD 58 (9) million, while taxes amounted to USD 365 (97) million. Net profit was USD 125 (112) million for the third quarter.

Investments in fixed assets amounted to USD 340 (226) million, driven by field development projects across the company's portfolio. The Aker BP-operated field developments of Ærfugl, Valhall Flank West and Skogul as well as the Johan Sverdrup development are all progressing according to plan. The company's capex estimate for 2018 has been reduced from around USD 1.3 billion to around USD 1.25 billion.

Abandonment payments ("abex") amounted to USD 72 (27) million, driven by a campaign to plug and abandon old wells on the Valhall field. This campaign has now been completed, within the revised abex estimate of USD 250 million for 2018.

The company's net interest-bearing debt was USD 2.85 billion at the end of the third quarter. Total available liquidity was USD 3.7 billion. In August, the company paid a quarterly dividend of USD 112.5 million or USD 0.3124 per share. The Board has resolved to pay the same amount in dividend in November.

In July, Aker BP entered into an agreement to acquire 11 licences, including four discoveries, from Total E&P Norge for USD 205 million. In October, the company entered into an agreement to acquire 77.8 percent of the King Lear discovery from Equinor for USD 250 million. Both transactions are subject to approval by Norwegian authorities.

Forward-looking statements in this report reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future.

All figures are presented in USD unless otherwise stated, and figures in brackets apply to the corresponding period in the previous year.

SUMMARY OF FINANCIAL RESULTS

	Unit	Q3 2018	Q3 2017	2018 YTD	2017 YTD
Operating income	USDm	1 000	596	2 864	1 837
EBITDA	USDm	736	395	2 129	1 277
Net result	USDm	125	112	422	241
Earnings per share (EPS)	USD	0.35	0.33	1.17	0.71
Production cost per barrel	USD/boe	11.9	11.1	11.8	9.9
Depreciation per barrel	USD/boe	13.6	14.5	13.1	14.2
Cash flow from operations	USDm	697	730	1 911	1 613
Cash flow from investments	USDm	- 457	-285	-1 237	-867
Total assets	USDm	12 364	9 116	12 364	9 116
Net interest-bearing debt (book value)	USDm	2 849	1 941	2 849	1 941
Cash and cash equivalents	USDm	127	81	127	81

SUMMARY OF PRODUCTION

	Unit	Q3 2018	Q3 2017	2018 YTD	2017 YTD
Alvheim (65%)	boepd	38 872	47 259	39 821	57 747
Bøyla (65%)	boepd	3 125	4 276	3 208	4 584
Gina Krog (3.3%)	boepd	1 317	1 453	1 556	490
Hod (90%) (37.5% in 2017)	boepd	872	500	983	549
Ivar Aasen (34.8%)	boepd	22 651	16 574	23 584	16 284
Skarv (23.8%)	boepd	23 313	24 518	25 981	28 458
Tambar / Tambar East (55.0%/46.2%)	boepd	4 008	2 145	3 681	2 275
Ula (80%)	boepd	6 498	6 468	6 115	6 629
Valhall (90%) (36.0% in 2017)	boepd	35 120	11 132	33 769	12 989
Vilje (46.9%)	boepd	3 716	5 063	4 296	5 485
Volund (65%)	boepd	11 016	12 316	12 579	4 325
Other	boepd	57	175	65	112
SUM	**boepd**	**150 566**	**131 880**	**155 637**	**139 928**
Oil price	USD/bbl	78	55	74	53
Gas price	**USD/scm**	**0.30**	**0.20**	**0.29**	**0.20**

FINANCIAL REVIEW

Income statement

(USD million)	Q3 2018	Q3 2017
Operating income	1 000	596
EBITDA	736	395
EBIT	548	219
Pre-tax profit/loss	490	209
Net profit	125	112
EPS (USD)	0.35	0.33

Total income in the third quarter amounted to USD 1,000 (596) million. The increase was driven by higher prices and increased production. Average realised hydrocarbon prices increased by 44 percent, and the production volume increased by 14 percent compared to the third quarter last year.

Production costs were USD 165 (134) million, and were relatively stable at USD 11.9 (11.1) per barrel of oil equivalent. The increase in the total production costs was caused by the increased interest in Valhall and Hod following the acquisition of Hess Norge in the fourth quarter 2017.

Exploration expenses amounted to USD 94 (64) million. During the quarter, the company participated in three exploration wells which were dry, increasing dry well expenses to USD 30 (21) million. Seismic acquisitions increased to USD 31 (16) million. Field evaluation expenses increased to USD 23 (8) million, mainly driven by concept studies for the NOAKA area.

Depreciation amounted to USD 189 (175) million, corresponding to 13.6 (14.5) USD/boe. No impairments were recorded in the quarter, compared to USD 1.1 million in the third quarter 2017.

Operating profit was USD 548 (219) million. Net financial expenses amounted to USD 58 (9) million. The main difference was within derivatives, which had a net effect of only USD 0.1 million in the quarter, compared to a net gain of USD 47 million in the comparative period.

Profit before taxes amounted to USD 490 (209) million. Taxes amounted to USD 365 (97) million for the third quarter, representing a calculated tax rate of 74.5 (46.4) percent. The calculated tax rate increased due to higher income, which reduced the relative significance of the capex uplift. In addition, the tax rate in the comparative period was lower than normal due to positive currency effects.

Net profit for the third quarter was USD 125 (112) million. Earnings per share were USD 0.35 (0.33).

Statement of financial position

(USD million)	Q3 2018	Q3 2017
Goodwill	1 860	1 817
PP&E	6 039	4 782
Cash & cash equivalents	127	81
Total assets	12 364	9 116
Equity	3 083	2 502
Interest-bearing debt	2 976	2 022

At the end of third quarter 2018, total intangible assets amounted to USD 3,839 (3,433) million, of which goodwill was USD 1,860 (1,817) million.

Property, plant and equipment increased to USD 6,039 (4,782) million, primarily driven by the acquisition of Hess Norge which took place in the fourth quarter 2017, as well as investments in development projects. Current tax receivables amounted to USD 1,607 (145) million at the end of the quarter, primarily related to a tax loss assumed through the Hess Norge acquisition, which is expected to be disbursed in the fourth quarter of 2018.

Cash and cash equivalents were USD 127 (81) million at the end of the quarter. Total assets were USD 12,364 (9,116) million.

Equity amounted to USD 3,083 (2,502) million at the end of the third quarter, corresponding to an equity ratio of 25 (27) percent. The increase was caused by total comprehensive income of USD 491 million and an equity issue with net proceeds of USD 489 million, adjusted for USD 400 million in dividend payments in the period from 1 October 2017 to 30 September 2018.

Deferred tax liabilities amounted to USD 1,671 (1,137) million and are detailed in note 7 to the financial statements.

Gross interest-bearing debt was USD 2,976 (2,022) million, consisting of the DETNOR02 bond of USD 236 million, the AKERBP Senior Notes (17/22) of USD 393 million, the AKERBP Senior Notes (18/25) of USD 493 million, the Reserve Based Lending ("RBL") facility of USD 354 million and a bank term loan of USD 1,500 million. The latter will be repaid when the previously mentioned tax loss related to the Hess Norge acquisition is disbursed.

Cash flow

(USD million)	Q3 2018	Q3 2017
Cash flow from operations	697	730
Cash flow from investments	-457	-285
Cash flow from financing	-163	-427
Net change in cash & cash eq.	78	18
Cash and cash eq. EOQ	127	81

Net cash flow from operating activities was USD 697 (730) million in the third quarter. Excluding a tax refund of USD 264 million received in the third quarter 2017, this represents an increase of USD 230 million. The main underlying driver for this improvement was increased production and higher realized prices.

Net cash flow to investment activities was USD 457 (285) million, of which investments in fixed assets amounted to USD 340 (226) million for the quarter, mainly related to Johan Sverdrup, Valhall and Alvheim. Investments in intangible assets including capitalized exploration were USD 45 (33) million in the quarter. Payments for decommissioning activities amounted to USD 72 (27) million in the quarter, and were related to plugging and abandonment of depleted wells at Valhall.

Net cash flow to financing activities totalled USD 163 (427) million, reflecting debt repayment of USD 50 million and dividend disbursements of USD 112.5 million during the quarter.

Funding

At the end of the third quarter, the company had total available liquidity of USD 3.7 (2.6) billion, comprising of cash and cash equivalents of USD 127 (81) million and undrawn credit facilities of USD 3,600 (2,540) million.

Hedging

The company seeks to reduce the risk related to foreign exchange rates, interest rates and commodity prices through hedging instruments. The company actively manages its exposures through a mix of forward contracts and options.

For the fourth quarter 2018, the company holds put options for 25 percent of the expected oil production, corresponding to approximately 87 percent of the after-tax value. The average strike price for these options is USD 55 per barrel (Brent).

For first half 2019, the company holds put options for 16 percent of expected oil production, corresponding to 56 percent of the after-tax value, at an average strike price of USD 58 per barrel.

Dividends

A quarterly dividend of USD 112.5 million, corresponding to USD 0.3124 per share was disbursed on 9 August 2018.

On 18 October 2018, the Board of Directors declared a quarterly dividend of USD 0.3124 per share, to be disbursed on or about 9 November 2018. This will take the total dividend payments for 2018 to USD 450 million.

OPERATIONAL REVIEW

Aker BP produced 13.9 (12.1) mmboe in the third quarter of 2018, corresponding to 150.6 (131.9) mboepd. The average realized oil price was USD 78 (55) per barrel, while the average realized gas price was USD 0.30 (0.20) per standard cubic metre (scm).

Alvheim Area

PL036C/036D/088BS/150/203/340/340BS (operator)

The producing fields Alvheim (65 percent), Volund (65 percent), Bøyla (65 percent) and Vilje (46.9 percent) are all tied back to the Alvheim FPSO.

Third quarter production from the Alvheim area was 56.7 mboepd net to Aker BP, down six percent from the previous quarter due to ordinary decline and a planned maintenance shutdown.

The production efficiency for the Alvheim area was 96 percent in the quarter.

Valhall Area

PL006B/033/033B (operator)

The Valhall area consists of the producing fields Valhall (90 percent) and Hod (90 percent).

Third quarter production from the Valhall area was 36.0 mboepd net to Aker BP. This represents a seven percent increase from the previous quarter, which was negatively impacted by planned maintenance and reduced production due to drilling operations.

As part of the Valhall IP drilling campaign, the company has tested a new well stimulation method which is expected to significantly reduce the time and cost of new wells. The testing has taken more time than anticipated due to technical difficulties. The first new IP well this year started production in August, several months behind plan. The second well is currently undergoing conventional stimulation, and is expected to start production during the fourth quarter.

The P&A campaign at Valhall was completed in early October, and the Maersk Invincible rig has been redeployed to perform drilling elsewhere at the Valhall field.

The production efficiency for the Valhall area was 88 percent in the quarter.

Ula Area

PL019/065/300 (operator)

The Ula area consists of the producing fields Ula (80.0 percent), Tambar (55.0 percent) and Tambar East (46.2 percent). Tambar and Tambar East are tied back to the Ula facilities, together with the Repsol operated Blane field.

Third quarter production from the Ula area was 10.5 mboepd net to Aker BP, marginally lower than previous quarter. A flotel is now in operation at the field to provide extra accommodation capacity to facilitate timely completion of project work.

The production efficiency for the Ula area was 72 percent in the quarter.

Skarv Area

PL159/212/212B/262 (operator)

The Skarv area consists of the Skarv producing field (23.835 percent). In addition, production from the Ærfugl A-1 H well is included in the Skarv volumes.

Third quarter production from the Skarv area was 23.3 mboepd net to Aker BP, which was 15 percent lower than in the previous quarter.

In the previous quarter, Skarv experienced issues with the gas injection system. This lead to temporarily higher gas export than normal. During the third quarter, gas injection was increased to re-pressurize the affected reservoir segments. As a result, gas exports were below normal in the third quarter.

One well remains shut in due to Xmas tree issues. An in-situ repair method has been developed and will be tested in the fourth quarter.

Skarv was also shut in for five days at the end of the quarter due to a planned ESD test.

The production efficiency for the Skarv area was 96 percent in the quarter.

Ivar Aasen

PL001B/242/457BS (operator)
The Ivar Aasen field (34.786 percent) is developed in coordination with the Edvard Grieg field, which provides Ivar Aasen with power, processing and export solutions.

Production from Ivar Aasen was 22.7 mboepd net to Aker BP in the third quarter, four percent below the previous quarter. The reduction was primarily driven by lower gas exports. The new water injectors drilled in 2018 have improved the ability to control reservoir pressure development, allowing for a more fine-tuned drainage resulting in a higher oil/gas ratio.

The average plant availability of Ivar Aasen was 98 percent in the period, up from 93 percent previous quarter. Production was negatively impacted by Edvard Grieg availability due to power generation issues, resulting in a production efficiency of 92 percent in the quarter.

HEALTH, SAFETY, SECURITY AND THE ENVIRONMENT

HSSE is always the number one priority in all of Aker BP's activities. The company strives to ensure that all its operations, drilling campaigns and projects are carried out under the highest HSSE standards.

	Unit	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017
Total recordable injury frequency (TRIF)	Per mill. exp. hours	4.1	4.2	1.9	5.3	0.7
Serious incident frequency (SIF)	Per mill. exp. hours	0.6	0.6	1.3	0.7	0.7
Loss of primary containment (LOPC)	Count	1	0	1	1	0
Process safety events Tier 1 and 2	Count	1	1	1	1	0
CO2 emissions intensity	Kg CO2/boe	7.5	6.8	7.4	7.0	7.4

The Total recordable injuries frequency (TRIF) in the third quarter was 4.1 (0.7) per million exposure hours, higher than the third quarter 2017 due to several medical treatment cases during the summer period.

The Serious incident frequency (SIF) in the third quarter was 0.6 (0.7) per million exposure hours, slightly down from the third quarter 2017.

The CO2 emissions intensity in the third quarter is below the company's target of maximum 8 kg CO2 per barrel.

PROJECTS

Johan Sverdrup Unit

PL265/501/502 (partner)

Phase 1 of the Johan Sverdrup (11.5733 percent) development project is progressing steadily. In August the Operator published a one-month acceleration of expected production start, now by November 2019. Phase 1 consists of a field centre with four fixed platforms, three subsea templates, oil and gas export pipelines, power from shore and 36 production and injection wells.

At the end of the third quarter, approximately 93 percent of the Phase 1 facilities were complete. In August the last two steel jackets were installed, for the living quarter platform (LQ) and Phase 1 processing platform (P1), to be installed next spring. Installation of Norway's biggest oil export pipeline (36", 282 km) from Mongstad to the field was completed in September, and installation of the gas export pipeline to Statpipe/Kårstø commenced.

In August/September the last two predrilled water injection wells were drilled and completed, thus completing the pre-drill program of 8 production wells and 12 water injectors.

PDO for Phase 2 was handed over to the Minister for Petroleum and Energy 27 August, according to plan. Phase 2 production start-up is expected in fourth quarter 2022. Phase 2 includes 28 additional production and injection wells in the peripheral parts of the field, increasing the total number of wells to 64.

Phase 2 also includes an increased production capacity on a fifth platform at the field centre (P2), increasing the capacity from 440,000 to 660,000 barrels of oil per day.

In addition, Phase 2 includes increased power-from-shore capacity, which will allow Johan Sverdrup to supply the surrounding fields Ivar Aasen, Edvard Grieg and Gina Krog with power, with total capacity of 300 mW (Phase 1 plus Phase 2). Johan Sverdrup will have very low CO2 emissions of only 0,67 kg per barrel.

In August the operator further reduced the Phase 1 CAPEX estimate by NOK 2 billion to NOK 86 billion (nominal at project currency), which is NOK 37 billion (30 percent) lower than at the time the PDO was submitted in 2015. The CAPEX for Phase 2 is estimated to NOK 41 billion, which is approximately half the cost estimated for Phase 2 when the PDO for Phase 1 was submitted.

In August the operator increased the Johan Sverdrup reserves estimate by 0.1 billion boe, providing a new uncertainty span of between 2.2 and 3.2 billion boe (previously 2.1 to 3.1) with a most likely estimate of 2.7 billion boe. The Operator estimates the full field break-even oil price to be below USD 20 per barrel.

Valhall Flank West

PL006B/033/033B (operator)

The Valhall Flank West project aims to continue the development of the Tor Formation on the western flank of the Valhall field, with planned production start in fourth quarter 2019. Valhall Flank West will be developed from a new Normally Unmanned Installation ("NUI"), tied back to the Valhall field centre for processing and export. Recoverable reserves are estimated at around 60 million barrels of oil equivalents. Gross investments for the development are estimated at NOK 5.5 billion in real terms. The PDO for Valhall Flank West was approved in March 2018.

The project is progressing as planned with excellent HSE performance and within budget. Engineering of the topside and jacket is completed and current engineering activity is focused on supporting ongoing topside construction of the normally unmanned installation in Verdal, Norway. A successful offshore campaign has prepared the field for subsea installation activities in 2019. Production of the flexible flowlines continues as planned. At the Valhall Central Complex modification work has been slightly disrupted due to rig activities, however this schedule delay is expected to be recovered by year end.

Valhall Flank North Water Injection

PL006B/033/033B (operator)

The Valhall Flank North Water Injection project aims to expand water injection capability to Valhall's northern drainage area, thus supporting Valhall production through enabling water injection to existing depleted areas and offering a potential for increasing the recovery from the reservoir by 7.8 mmboe gross. The project was sanctioned in first quarter 2018. The plan is to start drilling operations in fourth quarter 2018, and to start water injection in second quarter 2019 when pipelines and risers have been installed. Total investment is approximately USD 100 million.

Aker BP has on behalf of the Valhall partners entered into contracts with Subsea 7 for flexible riser and pipeline, and with Aker Solutions for modifications on the Valhall North Flank NUI and on the Valhall field centre. The Valhall Flank North Water Injection project will be organized and executed according to Aker BP's alliance model, and a drilling contract has been signed with Maersk Drilling.

North of Alvheim and Askja-Krafla (NOAKA)

PL442/026B/364 (operator) and PL272 (partner)

The North of Alvheim and Askja-Krafla ("NOAKA") area consists of the discoveries Frigg Gamma Delta, Langfjellet, Frøy, Fulla, Frigg, Rind and Askja-Krafla. Gross resources in the area are estimated to be more than 500 mmboe.

Aker BP and the other partners have performed detailed studies of different development solutions for the NOAKA area. The premise defined by the authorities, and confirmed in recent dialogue, has been that a development should capture all discovered resources in the area and facilitate future tie-ins of new discoveries.

These studies have resulted in two alternative development solutions. One solution involves two unmanned production platforms ("UPP") or similar concepts, supported from an existing host in the area. The other solution involves a new hub platform in the central part of the area, with processing and living quarters ("PQ").

Aker BP's recommendation is to develop the area with the PQ concept. This concept is the only alternative that allows for economic recovery of all discovered resources in the area, and provides higher resource recovery and socio-economic benefits than the alternative. The PQ concept is also the better alternative with regards to exploiting additional resources that may be discovered through future exploration.

Aker BP's ambition is to make NOAKA the first energy positive field development on the Norwegian Continental Shelf. The goal is full electrification and zero emissions, enabled by power from shore. A study has been performed in order to combine a NOAKA development with an offshore wind park. Aker BP aims to build further on its Ivar Aasen experience with onshore control rooms and a high degree of digitalization and automation to achieve maximum operational efficiency and the highest safety standards.

The NOAKA PQ concept will be a new major field development on the Norwegian Continental Shelf. Building on the positive experience from the alliance model, the ambition is to set a new standard in terms of cost per installed ton on the NCS. Aker BP is ready to make a concept selection in 2018, and will continue working with its partners, suppliers and the authorities to realize the NOAKA project.

Skogul

PL460 (operator)

Skogul will be developed with a single multilateral production well tied back to the Vilje field, utilizing the existing pipeline from Vilje to the Alvheim FPSO. Recoverable reserves are estimated at around 10 mmboe gross, and total investments at NOK 1.5 billion in real terms. Production start is planned for the first quarter of 2020. The PDO was approved by Norwegian authorities in March 2018. The production well at Skogul will be subsea production well number 35 in the Alvheim area. It represents Aker BP's continuous effort to maximize value and extend the economic life in the Alvheim area.

Ærfugl

PL162/159/212/212B (operator)

The PDO for the Ærfugl development was submitted in December 2017 and was approved by Norwegian authorities in April 2018. At the same time, the A-1H well which has previously been on test production was granted a permanent production permit.

Ærfugl will be developed in two phases. The first phase, which is currently in execution, includes three new production wells in the southern part of the field tied into the Skarv FPSO via a trace heated pipe-in-pipe flowline, in addition to the existing A-1 H well. Production is planned to begin late 2020.

The project is progressing on plan, and the work is performed by joint efforts from Aker BP and its strategic alliance partners. The project is executed on a global arena with work sites in Asia, Canada, several locations in Europe and Norway including the Helgeland region.

Currently, there is high activity with line pipe supplies, subsea structure fabrication, wellheads and the Vertical Xmas Tree system and components assembly.

The remaining technology qualification activities for the trace heat flowline system and the new generation of Vertical Xmas Tree systems are on plan and well underway to be ready for assembly and construction work starting in 2019. Offshore mobilisation for the modification work required on the Skarv FPSO is scheduled to start in the second quarter 2019.

The phase 2 of the development is currently in Select stage and is being matured towards concept select in first quarter 2019.

Tambar Development

PL065 (operator)

Tambar (55 percent) is a satellite field to Ula. The Tambar development project is targeting gross reserves of 27 mmboe, which is expected to extend the economic life of the field to at least 2028. The project consists of two additional wells and gas lift. The new wells were completed and began producing late in the second quarter. Completion of the gas lift project is now scheduled to commence in the second quarter 2019 pending completion of the remaining facilities modifications.

Oda

PL405 (partner)

The Oda field (15 percent) is being developed with a subsea template tied back to the Ula Field Centre via the existing Oselvar infrastructure. Oselvar production was closed down 1 April 2018. The project involves two production wells and one water injector. Aker BP performs the required facility modifications to receive production from and provide injection water to Oda.

Oda's recoverable reserves are estimated at 48 mmboe (gross). Natural gas from Oda will support the Ula development strategy by providing gas for the WAG injection regime. Offshore execution of topside and facility modifications on the Ula field centre to receive Oda production is ongoing. First oil from Oda is expected in second quarter 2019.

EXPLORATION

During the quarter, the company's cash spending on exploration was USD 109 million. Of this, USD 94 million was recognized as exploration expenses in the period, relating to seismic, area fees, field evaluations and G&G costs.

Spirit Energy Norge AS completed drilling of the Scarecrow prospect in PL852 (Aker BP 40 %) in August. The objective of the well was to test a new play model in the Cretaceous succession, but no reservoir was found and the well was dry.

DEA Norge AS completed drilling of the Gråspett prospect in PL721 (Aker BP 40 %) in September. The objective of the well was to prove hydrocarbon filled reservoir in the upper Triassic – middle Jurassic Realgrunnen Group, but the well was dry. Preliminary results show that both reservoirs were present in the well, but no significant hydrocarbon shows were detected.

On 4 September, Aker BP delivered several applications in the annual APA round, representing a mixture of applications for new acreage around the company's existing producing hubs in addition to potential new growth areas on the NCS. The licenses are expected to be awarded in January 2019.

In the Alvheim area, drilling of the Gekko appraisal well started in September, and was completed in early October. The well discovered additional volumes of oil and gas, increasing the probability of a development of Gekko as a tie-back to the Alvheim FPSO.

BUSINESS DEVELOPMENT

Acqusition of Total portfolio

In July 2018, Aker BP entered into an agreement with Total E&P Norge to acquire its interests in a portfolio of 11 licences on the Norwegian Continental Shelf for a cash consideration of USD 205 million. The portfolio includes four discoveries with net recoverable resources of 83 million barrels oil equivalents ("mmboe"), based on estimates from the Norwegian Petroleum Directorate.

Two of the discoveries, Trell and Trine, are located near the Aker BP-operated Alvheim field and are expected to be produced through the Alvheim FPSO.

The Alve Nord discovery is located north of the Aker BP-operated Skarv field, and can be produced through the Skarv FPSO.

The Rind discovery is part of the NOAKA area, where Aker BP is working towards a new area development.

In addition to these discoveries, the transaction also provided the company with increased equity interest in exploration acreage near the Aker BP-operated Ula field. The transaction is subject to approval by Norwegian authorities.

Acqusition of King Lear discovery

On 15 October 2018, Aker BP entered into an agreement with Equinor Energy to acquire its 77.8 percent interest in the King Lear gas/condensate discovery in the Norwegian North Sea for a cash consideration of USD 250 million.

The King Lear discovery has gross estimated recoverable volumes of 99 mmboe according to data form the Norwegian Petroleum Directorate, and is one of the largest undeveloped discoveries on the Norwegian Continental Shelf.

Aker BP's goal is to develop King Lear as a satellite to Ula, which would improve the capacity utilization at the Ula facilities and provide significant additional volumes of injection gas to support increased oil recovery from the Ula field. When including the increased oil recovery potential from Ula, Aker BP estimates the total resource addition net to the company to be more than 100 mmboe.

King Lear is located approximately 50 km south of the Ula field centre, in production licences 146 and 333. The transaction covers Equinor Energy's 77.8 percent interest in the two licences. The transaction is subject to approval by Norwegian authorities.

OUTLOOK

The company continues to build on a strong platform for further value creation through safe operations, an effective business model built on lean principles, technological competence and industrial cooperation to secure long term competitiveness.

The company has a robust balance sheet, providing the company with ample financial flexibility going forward, and will continue to pursue selective growth opportunities.

For 2018, the company has previously communicated a production estimate of 155-160 mboepd. The average production for the first nine months was 155.6 mboepd, and the company now expects full year production to be in the lower half of the estimated range.

Production cost has averaged 11.8 USD/boe for the first nine months. For the full year 2018, the company maintains its estimate of around 12 USD/boe.

Capex (excluding capitalized interest) totalled USD 823 million for the first nine months of 2018. The company's full-year capex estimate has been reduced from around USD 1.3 billion to around USD 1.25 billion.

The company expects to participate in three or four exploration wells in the fourth quarter, in addition to the recently completed Gekko appraisal well. The total exploration spend for 2018 is estimated to approximately USD 400 million, revised down from USD 425 due to later arrival of a drilling rig.

The P&A campaign at Valhall has now been completed ahead of schedule, and the total abandonment spend for 2018 is likely to end up within the previously communicated estimate of USD 250 million.

A quarterly dividend of USD 0.3124 per share is scheduled to be paid in November. This will take the total dividend payments for 2018 to a total of USD 450 million.

Financial statements with notes

INCOME STATEMENT (Unaudited)

		Group			
		Q3		01.01.-30.09.	
(USD 1 000)	Note	2018	2017	2018	2017
Petroleum revenues		981 084	600 808	2 850 662	1 838 450
Other operating income		18 547	-4 620	13 314	-1 511
Total income	2	**999 631**	**596 188**	**2 863 976**	**1 836 939**
Production costs		165 466	134 411	502 573	376 303
Exploration expenses	3	93 519	63 887	223 450	169 521
Depreciation	5	188 525	175 334	556 475	543 532
Impairments	4, 5	-	1 091	-	31 238
Other operating expenses		4 334	2 893	9 299	14 057
Total operating expenses		**451 845**	**377 617**	**1 291 796**	**1 134 651**
Operating profit		**547 787**	**218 571**	**1 572 180**	**702 288**
Interest income		7 914	2 566	18 820	4 725
Other financial income		34 130	54 522	74 982	84 752
Interest expenses		28 196	27 129	91 522	88 397
Other financial expenses		71 717	39 427	128 880	140 654
Net financial items	6	**-57 869**	**-9 469**	**-126 601**	**-139 574**
Profit before taxes		**489 918**	**209 102**	**1 445 580**	**562 714**
Taxes (+)/tax income (-)	7	365 047	97 065	1 023 464	321 963
Net profit		**124 871**	**112 037**	**422 116**	**240 751**
Weighted average no. of shares outstanding basic and diluted		360 113 509	337 737 071	360 113 509	337 737 071
Basic and diluted earnings USD per share		0.35	0.33	1.17	0.71

STATEMENT OF COMPREHENSIVE INCOME

		Group			
		Q3		01.01.-30.09.	
(USD 1 000)	Note	2018	2017	2018	2017
Profit for the period		124 871	112 037	422 116	240 751
Items which may be reclassified over profit and loss (net of taxes)					
Currency translation adjustment		6 506	-	9 369	-356
Total comprehensive income in period		**131 377**	**112 037**	**431 485**	**240 395**

STATEMENT OF FINANCIAL POSITION (Unaudited)

		Group		
(USD 1 000)	Note	30.09.2018	30.09.2017	31.12.2017
ASSETS				
Intangible assets				
Goodwill	5	1 860 126	1 817 486	1 860 126
Capitalized exploration expenditures	5	416 097	355 926	365 417
Other intangible assets	5	1 562 486	1 259 511	1 617 039
Tangible fixed assets				
Property, plant and equipment	5	6 038 954	4 781 618	5 582 493
Financial assets				
Long-term receivables		39 608	41 402	40 453
Long-term derivatives	11	-	23 238	12 564
Other non-current assets		10 506	6 041	8 398
Total non-current assets		**9 927 777**	**8 285 223**	**9 486 491**
Inventories				
Inventories		82 891	73 762	75 704
Receivables				
Accounts receivable		144 231	53 548	99 752
Tax receivables	7	1 607 118	145 245	1 586 006
Other short-term receivables	8	469 688	463 597	535 518
Short-term derivatives	11	5 574	14 106	2 585
Cash and cash equivalents				
Cash and cash equivalents	9	126 608	80 764	232 504
Total current assets		**2 436 109**	**831 022**	**2 532 069**
TOTAL ASSETS		**12 363 886**	**9 116 244**	**12 018 560**

STATEMENT OF FINANCIAL POSITION (Unaudited)

		Group		
(USD 1 000)	Note	30.09.2018	30.09.2017	31.12.2017
EQUITY AND LIABILITIES				
Equity				
Share capital		57 056	54 349	57 056
Share premium		3 637 297	3 150 567	3 637 297
Other equity		-611 771	-702 814	-705 756
Total equity		**3 082 581**	**2 502 102**	**2 988 596**
Non-current liabilities				
Deferred taxes	7	1 670 898	1 137 008	1 307 148
Long-term abandonment provision	15	2 887 356	2 210 726	2 775 622
Provisions for other liabilities	10	119 344	89 209	152 418
Long-term bonds	13	1 122 220	625 726	622 039
Long-term derivatives	11	17 169	8 356	13 705
Other interest-bearing debt	14	353 605	1 396 158	1 270 556
Current liabilities				
Trade creditors		86 620	72 787	32 847
Accrued public charges and indirect taxes		14 582	15 280	27 949
Tax payable	7	754 344	265 080	351 156
Short-term derivatives	11	1 587	2 128	7 691
Short-term abandonment provision	15	140 875	152 668	268 262
Short-term interest-bearing debt	14	1 499 693	-	1 496 374
Other current liabilities	12	613 012	639 016	704 197
Total liabilities		**9 281 305**	**6 614 142**	**9 029 964**
TOTAL EQUITY AND LIABILITIES		**12 363 886**	**9 116 244**	**12 018 560**

STATEMENT OF CHANGES IN EQUITY - GROUP (Unaudited)

(USD 1 000)	Share capital	Share premium	Other equity: Other paid-in capital	Other equity: Other comprehensive income: Actuarial gains/(losses)	Other equity: Other comprehensive income: Foreign currency translation reserves	Other equity: Retained earnings	Total other equity	Total equity
Equity as of 31.12.2017	**57 056**	**3 637 297**	573 083	-89	-90 383*	-1 188 366	**-705 756**	**2 988 596**
Dividend distributed	-	-	-	-	-	-225 000	-225 000	-225 000
Profit for the period	-	-	-	-	-	297 246	297 246	297 246
Other comprehensive income for the period	-	-	-	-	2 863	-	2 863	2 863
Equity as of 30.06.2018	**57 056**	**3 637 297**	573 083	-89	-87 521	-1 116 121	**-630 648**	**3 063 704**
Dividend distributed	-	-	-	-	-	-112 500	-112 500	-112 500
Profit for the period	-	-	-	-	-	124 871	124 871	124 871
Other comprehensive income for the period	-	-	-	-	6 506	-	6 506	6 506
Equity as of 30.09.2018	**57 056**	**3 637 297**	573 083	-89	-81 014	-1 103 750	**-611 771**	**3 082 581**

* The amount arose mainly as a result of the change in functional currency in Q4 2014.

STATEMENT OF CASH FLOW (Unaudited)

		Group				
		Q3		01.01.-30.09.		Year
(USD 1 000)	Note	2018	2017	2018	2017	2017
CASH FLOW FROM OPERATING ACTIVITIES						
Profit before taxes		489 918	209 102	1 445 580	562 714	811 128
Taxes paid during the period	7	-163 007	-34 091	-266 473	-34 091	-101 115
Tax refund during the period		-	263 791	-	263 791	404 704
Depreciation	5	188 525	175 334	556 475	543 532	726 670
Net impairment losses	4, 5	-	1 091	-	31 238	52 349
Accretion expenses	6, 15	31 504	32 757	96 656	97 212	129 619
Interest expenses	6	50 278	38 124	143 785	124 164	156 704
Interest paid		-48 419	-27 454	-135 956	-114 224	-145 940
Changes in derivatives	2, 6	23 252	-37 628	6 935	-67 568	-34 461
Amortized loan costs	6	7 147	12 901	22 866	30 564	36 900
Amortization of fair value of contracts	10	14 195	-825	42 580	7 330	11 728
Expensed capitalized dry wells	3, 5	29 766	20 534	61 428	56 155	75 401
Changes in inventories, accounts payable and receivables		-7 584	19 591	2 107	56 090	-7 583
Changes in other current balance sheet items		81 195	57 150	-65 440	55 633	39 387
NET CASH FLOW FROM OPERATING ACTIVITIES		**696 772**	**730 376**	**1 910 542**	**1 612 541**	**2 155 491**
CASH FLOW FROM INVESTMENT ACTIVITIES						
Payment for removal and decommissioning of oil fields	15	-72 266	-26 673	-226 476	-54 640	-85 733
Disbursements on investments in fixed assets		-339 571	-225 648	-897 837	-729 159	-977 462
Acquisitions of companies (net of cash acquired)		-	-	-	-	-2 055 033
Cash received from sale of licenses		-	-	-	-	170 959
Disbursements on investments in capitalized exploration expenditures and other intangible assets	5	-44 795	-32 750	-113 030	-83 201	-111 724
NET CASH FLOW USED IN INVESTMENT ACTIVITIES		**-456 633**	**-285 071**	**-1 237 343**	**-867 000**	**-3 058 994**
CASH FLOW FROM FINANCING ACTIVITIES						
Repayment of long-term debt		-50 000	-422 441	-930 252	-647 911	-777 911
Repayment of bond (DETNOR03)		-	-330 000	-	-330 000	-330 000
Net cash received from issuance of new shares		-	-	-	-	489 436
Net proceeds from issuance of debt		-	388 000	492 423	388 000	1 886 885
Paid dividend		-112 500	-62 500	-337 500	-187 500	-250 000
NET CASH FLOW FROM FINANCING ACTIVITIES		**-162 500**	**-426 941**	**-775 329**	**-777 411**	**1 018 410**
Net change in cash and cash equivalents		**77 639**	**18 365**	**-102 130**	**-31 870**	**114 906**
Cash and cash equivalents at start of period		49 245	65 569	232 504	115 286	115 286
Effect of exchange rate fluctuation on cash held		-276	-3 170	-3 766	-2 653	2 312
CASH AND CASH EQUIVALENTS AT END OF PERIOD	9	**126 608**	**80 764**	**126 608**	**80 764**	**232 504**
SPECIFICATION OF CASH EQUIVALENTS AT END OF PERIOD						
Bank deposits and cash		126 608	71 821	126 608	71 821	231 506
Restricted bank deposits		-	8 943	-	8 943	998
CASH AND CASH EQUIVALENTS AT END OF PERIOD	9	**126 608**	**80 764**	**126 608**	**80 764**	**232 504**

NOTES

(All figures in USD 1 000 unless otherwise stated)

These interim financial statements have been prepared in accordance with the International Financial Reporting Standards as adopted by the EU ("IFRS") IAS 34 "Interim Financial Reporting", thus the interim financial statements do not include all information required by IFRS and should be read in conjunction with the group's annual financial statement as at 31 December 2017. The interim financial statements reflect all adjustments which are, in the opinion of management, necessary for a fair statement of the financial position, results of operations and cash flows for the dates and interim periods presented. Interim period results are not necessarily indicative of results of operations or cash flows for an annual period. These interim financial statements have not been subject to review or audit by independent auditors.

These interim financial statements were authorised for issue by the Company's Board of Directors on 18 October 2018.

Note 1 Accounting principles

As described in the group's annual financial statements for 2017, two new accounting standards entered into force from 1 January 2018. IFRS 9 *Financial Instruments* does not have any significant impact on the group's financial statements. IFRS 15 *Revenue from contracts with customers* has no impact on the line item petroleum revenues in the income statement, but additional details have been provided in the note disclosures (note 2) to specify the part of revenues that arises from change in over/underlift balances. The adoption of IFRS 9 and IFRS 15 does not impact any line items in the balance sheet or have any impact on reported cashflows.

Except for the changes described above, the accounting principles used for this interim report are consistent with the principles used in the group's annual financial statements as at 31 December 2017.

In preparing these interim financial statements, management has made judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expense. Actual results may differ from these estimates.

The significant judgements made by management in applying the group's accounting policies and the key sources of estimation uncertainty are the same as those that applied to the annual financial statements as at 31 December 2017.

Note 2 Income

	Group			
	Q3		01.01.-30.09.	
Breakdown of petroleum revenues (USD 1 000)	**2018**	**2017**	**2018**	**2017**
Sales of liquids	807 052	479 802	2 394 558	1 559 679
Sales of gas	134 791	85 936	415 187	263 117
Tariff income	5 408	6 482	15 010	17 451
Total petroleum sales	**947 252**	**572 219**	**2 824 755**	**1 840 247**
Impact from change in over/underlift balances of liquids	33 832	28 588	25 907	-1 798
Total petroleum revenues	**981 084**	**600 808**	**2 850 662**	**1 838 450**
Breakdown of produced volumes (barrels of oil equivalent)				
Liquids	11 025 136	9 434 958	33 327 271	29 787 298
Gas	2 826 946	2 698 032	9 161 593	8 412 970
Total produced volumes	**13 852 082**	**12 132 990**	**42 488 864**	**38 200 268**
Other income (USD 1 000)				
Realized gain/loss (-) on oil derivatives	-4 698	-1 291	-12 131	-4 892
Unrealized gain/loss (-) on oil derivatives	-822	-6 353	-3 143	-947
Gain on license transactions	404	2 718	404	3 274
Other income*	23 664	306	28 183	1 054
Total other income	**18 547**	**-4 620**	**13 314**	**-1 511**

* Mainly related to a non-recurring tariff compensation that has been settled and paid in Q3.

Note 3 Exploration expenses

	Group			
	Q3		01.01.-30.09.	
Breakdown of exploration expenses (USD 1 000)	**2018**	**2017**	**2018**	**2017**
Seismic	30 639	15 840	74 151	43 647
Area fee	2 097	3 653	8 673	12 225
Field Evaluation	22 503	7 803	51 541	25 691
Dry well expenses*	29 766	20 534	61 428	56 155
Other exploration expenses	8 512	16 057	27 655	31 802
Total exploration expenses	**93 519**	**63 887**	**223 450**	**169 521**

* Mainly related to the Gråspett, Scarecrow and Slengfehøgda wells

Note 4 Impairments

Impairment testing

Impairment tests of individual cash-generating units are performed when impairment triggers are identified, and for goodwill impairment is tested at least annually.

As described in previous financial reporting, the technical goodwill recognized in relation to prior year`s business combinations, will be subject to impairment charges as it is fully allocated to the respective individual CGU's. Hence, a quarterly impairment charge is expected if all assumptions remain unchanged. However, in Q3 2018 there has been a positive impact from increase in petroleum prices, which together with the headroom from prior periods, results in no impairment of technical goodwill in the period.

Note 5 Tangible fixed assets and intangible assets

TANGIBLE FIXED ASSETS - GROUP

(USD 1 000)	Assets under development	Production facilities including wells	Fixtures and fittings, office machinery	Total
Book value 31.12.2017	**1 480 689**	**4 032 797**	**69 007**	**5 582 493**
Acquisition cost 31.12.2017	**1 480 689**	**6 057 801**	**104 346**	**7 642 835**
Additions	524 194	57 607	6 191	587 991
Disposals	-	-	-	-
Reclassification	-178 321	171 404	7 839	922
Acquisition cost 30.06.2018	**1 826 562**	**6 286 811**	**118 375**	**8 231 748**
Accumulated depreciation and impairments 31.12.2017	**-**	**2 025 004**	**35 338**	**2 060 342**
Depreciation	-	326 937	9 332	336 269
Impairment	-	-	-	-
Retirement/transfer depreciations	-	-	-	-
Accumulated depreciation and impairments 30.06.2018	**-**	**2 351 941**	**44 670**	**2 396 611**
Book value 30.06.2018	**1 826 562**	**3 934 870**	**73 705**	**5 835 137**
Acquisition cost 30.06.2018	**1 826 562**	**6 286 811**	**118 375**	**8 231 748**
Additions	267 852	94 707	6 911	369 470
Disposals	-	-	-	-
Reclassification	-13 532	13 532	-	-
Acquisition cost 30.09.2018	**2 080 882**	**6 395 050**	**125 286**	**8 601 218**
Accumulated depreciation and impairments 30.06.2018	**-**	**2 351 941**	**44 670**	**2 396 611**
Depreciation	-	159 895	5 757	165 653
Impairment	-	-	-	-
Retirement/transfer depreciations	-	-	-	-
Accumulated depreciation and impairments 30.09.2018	**-**	**2 511 836**	**50 428**	**2 562 264**
Book value 30.09.2018	**2 080 882**	**3 883 214**	**74 858**	**6 038 954**

Capitalized exploration expenditures are reclassified to "Fields under development" when the field enters into the development phase. If development plans are subsequently re-evaluated, the associated costs remain in assets under development and are not reclassified back to exploration assets. Fields under development are reclassified to "Production facilities" from the start of production. Production facilities, including wells, are depreciated in accordance with the Unit of Production Method. Office machinery, fixtures and fittings etc. are depreciated using the straight-line method over their useful life, i.e. 3 - 5 years. Removal and decommissioning costs are included as production facilities or fields under development.

INTANGIBLE ASSETS - GROUP

(USD 1 000)	Other intangible assets Licences etc.	Software	Total	Exploration wells	Goodwill
Book value 31.12.2017	**1 617 005**	**34**	**1 617 039**	**365 417**	**1 860 126**
Acquisition cost 31.12.2017	**1 933 241**	**7 501**	**1 940 742**	**365 417**	**2 738 973**
Additions	-	-	-	68 235	-
Disposals/expensed dry wells	-	-	-	31 662	-
Reclassification	-	-	-	-922	-
Acquisition cost 30.06.2018	**1 933 241**	**7 501**	**1 940 742**	**401 069**	**2 738 973**
Accumulated depreciation and impairments 31.12.2017	**316 236**	**7 467**	**323 703**	**-**	**878 847**
Depreciation	31 672	8	31 681	-	-
Impairment	-	-	-	-	-
Retirement/transfer depreciations	-	-	-	-	-
Accumulated depreciation and impairments 30.06.2018	**347 908**	**7 476**	**355 384**	**-**	**878 847**
Book value 30.06.2018	**1 585 333**	**25**	**1 585 358**	**401 069**	**1 860 126**
Acquisition cost 30.06.2018	**1 933 241**	**7 501**	**1 940 742**	**401 069**	**2 738 973**
Additions	-	-	-	44 795	-
Disposals/expensed dry wells	-	-	-	29 766	-
Reclassification	-	-	-	-	-
Acquisition cost 30.09.2018	**1 933 241**	**7 501**	**1 940 742**	**416 097**	**2 738 973**
Accumulated depreciation and impairments 30.06.2018	**347 908**	**7 476**	**355 384**	**-**	**878 847**
Depreciation	22 868	4	22 872	-	-
Impairment	-	-	-	-	-
Retirement/transfer depreciations	-	-	-	-	-
Accumulated depreciation and impairments 30.09.2018	**370 777**	**7 480**	**378 257**	**-**	**878 847**
Book value 30.09.2018	**1 562 464**	**21**	**1 562 486**	**416 097**	**1 860 126**

	Group			
	Q3		01.01.-30.09.	
Depreciation in the income statement (USD 1 000)	**2018**	**2017**	**2018**	**2017**
Depreciation of tangible fixed assets	165 653	153 299	501 922	472 899
Depreciation of intangible assets	22 872	22 035	54 553	70 633
Total depreciation in the income statement	**188 525**	**175 334**	**556 475**	**543 532**
Impairment in the income statement (USD 1 000)				
Impairment/reversal of tangible fixed assets	-	128	-	121
Impairment/reversal of intangible assets	-	963	-	1 956
Impairment of goodwill	-	-	-	29 161
Total impairment in the income statement	**-**	**1 091**	**-**	**31 238**

Note 6 Financial items

(USD 1 000)	Group Q3 2018	Group Q3 2017	Group 01.01.-30.09. 2018	Group 01.01.-30.09. 2017
Interest income	**7 914**	**2 566**	**18 820**	**4 725**
Realized gains on derivatives	32 757	7 746	69 199	9 769
Change in fair value of derivatives	1 373	43 982	5 783	68 515
Net currency gains	-	2 794	-	6 468
Total other financial income	**34 130**	**54 522**	**74 982**	**84 752**
Interest expenses	50 278	38 124	143 785	124 164
Capitalized interest cost, development projects	-29 229	-23 895	-75 129	-66 331
Amortized loan costs	7 147	12 901	22 866	30 564
Total interest expenses	**28 196**	**27 129**	**91 522**	**88 397**
Net currency losses	5 752	-	3 861	-
Realized loss on derivatives	10 432	4 997	17 169	7 858
Change in fair value of derivatives	23 803	-	9 575	-
Accretion expenses	31 504	32 757	96 656	97 212
Other financial expenses	227	1 674	1 619	35 584
Total other financial expenses	**71 717**	**39 427**	**128 880**	**140 654**
Net financial items	**-57 869**	**-9 469**	**-126 601**	**-139 574**

Note 7 Tax

Tax for the period appear as follows (USD 1 000)	Group Q3 2018	Group Q3 2017	Group 01.01.-30.09. 2018	Group 01.01.-30.09. 2017
Calculated current year tax	219 486	66 465	670 121	207 000
Change in deferred tax in the income statement	145 895	27 833	375 441	112 736
Prior period adjustments	-333	2 767	-22 098	2 227
Total tax (+)/tax income (-)	**365 047**	**97 065**	**1 023 464**	**321 963**

Calculated tax receivable (+)/tax payable (-) (USD 1 000)	Group 30.09.2018	Group 30.09.2017	Group 31.12.2017
Tax receivable/payable at 01.01.	1 234 850	307 977	307 977
Current year tax (-)/tax receivable (+)	-670 121	-206 837	-332 092
Taxes receivable/payable related to acquisitions/sales	-	-1 010	1 523 512
Net tax payment (+)/tax refund (-)	266 473	-229 700	-303 589
Prior period adjustments	12 131	9 711	9 502
Currency movements of tax receivable/payable	9 441	24	29 540
Total net tax receivable (+)/tax payable (-)	**852 774**	**-119 835**	**1 234 850**
Tax receivable included as current assets (+)	1 607 118	145 245	1 586 006
Tax payable included as current liabilities (-)	-754 344	-265 080	-351 156

Deferred tax (-)/deferred tax asset (+) (USD 1 000)	**Group** 30.09.2018	30.09.2017	31.12.2017
Deferred tax/deferred tax asset 01.01.	-1 307 148	-1 045 542	-1 045 542
Change in deferred tax in the income statement	-375 441	-112 736	-202 715
Deferred tax related to acquisitions/sales	-	19 190	-61 877
Prior period adjustment	11 691	2 080	2 982
Deferred tax charged to OCI and equity	-	-	5
Net deferred tax (-)/deferred tax asset (+)	**-1 670 898**	**-1 137 008**	**-1 307 148**

	Group			
	Q3		**01.01.-30.09.**	
Reconciliation of tax expense (USD 1 000)	**2018**	**2017**	**2018**	**2017**
78% tax rate on profit before tax	382 136	162 822	1 127 552	438 639
Tax effect of uplift	-32 382	-30 027	-97 236	-92 274
Permanent difference on impairment	-	-	-	22 813
Foreign currency translation of NOK monetary items	4 486	-2 067	3 012	-4 933
Foreign currency translation of USD monetary items	2 148	84 627	9 315	131 289
Tax effect of financial and other 23%/24% items	13 916	-33 492	8 900	-42 989
Currency movements of tax balances*	-8 779	-82 614	-10 394	-132 524
Other permanent differences and prior period adjustment	3 524	-2 184	-17 685	1 942
Total taxes (+)/tax income (-)	**365 047**	**97 065**	**1 023 464**	**321 963**

* Tax balances are in NOK and converted to USD using the period end currency rate. When NOK weakens against USD, the tax rate increases as there is less remaining tax depreciation measured in USD (vice versa).

The tax rate for general corporation tax changed from 24 to 23 per cent from 1 January 2018. The rate for special tax changed from the same date from 54 to 55 per cent.

In accordance with statutory requirements, the calculation of current tax is required to be based on NOK functional currency. This may impact the effective tax rate as the company's functional currency is USD.

Note 8 Other short-term receivables

(USD 1 000)	**Group** 30.09.2018	30.09.2017	31.12.2017
Prepayments	56 607	29 604	59 100
VAT receivable	10 228	9 163	10 856
Underlift of petroleum	175 970	51 308	118 012
Accrued income from sale of petroleum products	103 718	116 222	105 670
Other receivables, mainly from licenses	123 164	257 300	241 879
Total other short-term receivables	**469 688**	**463 597**	**535 518**

Note 9 Cash and cash equivalents

The item 'Cash and cash equivalents' consists of bank accounts and short-term investments that constitute parts of the group's transaction liquidity.

Breakdown of cash and cash equivalents (USD 1 000)	**30.09.2018**	**Group** **30.09.2017**	**31.12.2017**
Bank deposits	126 608	71 821	231 506
Restricted funds (tax withholdings)*	-	8 943	998
Cash and cash equivalents	**126 608**	**80 764**	**232 504**
Unused revolving credit facility	-	-	-
Unused reserve-based lending facility (see note 14)	3 600 000	2 540 000	2 670 000

* During Q4 2017, the company extended its bank guarantee related to withheld payroll tax to NOK 300 million. In Q1 2018 the remaining restricted funds were released in full.

Note 10 Provisions for other liabilities

Breakdown of provisions for other liabilities (USD 1 000)	**30.09.2018**	**Group** **30.09.2017**	**31.12.2017**
Fair value of contracts assumed in acquisitions*	116 789	80 766	149 031
Other long term liabilities	2 555	8 443	3 387
Total provisions for other liabilities	**119 344**	**89 209**	**152 418**

* The negative contract values are mainly related to rig contracts entered into by companies acquired by Aker BP, which differed from current market terms at the time of the acquisitions. The fair value is based on the difference between market price and contract price at the time of the acquisitions. The balance is split between current and non-current liabilities based on the cash flow in the contracts, and amortized over the lifetime of the contracts.

Note 11 Derivatives

(USD 1 000)	**30.09.2018**	**Group** **30.09.2017**	**31.12.2017**
Unrealized gain currency contracts	-	23 238	12 564
Long-term derivatives included in assets	**-**	**23 238**	**12 564**
Unrealized gain on commodity derivatives	-	-	-
Unrealized gain currency contracts	5 574	14 106	2 585
Short-term derivatives included in assets	**5 574**	**14 106**	**2 585**
Total derivatives included in assets	**5 574**	**37 344**	**15 149**
Unrealized losses on commodity derivatives	9 247	-	-
Unrealized losses interest rate swaps	7 922	8 356	13 705
Long-term derivatives included in liabilities	**17 169**	**8 356**	**13 705**
Unrealized losses commodity derivatives	1 587	2 128	7 691
Short-term derivatives included in liabilities	**1 587**	**2 128**	**7 691**
Total derivatives included in liabilities	**18 756**	**10 484**	**21 396**

The group has various types of economic hedging instruments. Commodity derivatives are used to hedge the risk of oil price reduction. The group manages its interest rate exposure using interest rate derivatives, including a cross currency interest rate swap. Foreign currency exchange derivatives are used to manage the company's exposure to currency risks, mainly NOK, EUR and GBP. These derivatives are mark to market with changes in market value recognized in the income statement. The nature of the instruments and the valuation method is consistent with the disclosed information in the annual financial statements as at 31 December 2017.

Note 12 Other current liabilities

Breakdown of other current liabilities (USD 1 000)	**30.09.2018**	**Group** **30.09.2017**	**31.12.2017**
Current liabilities against JV partners	29 052	78 595	81 223
Share of other current liabilities in licences	338 791	389 230	409 387
Overlift of petroleum	40 211	1 940	9 610
Fair value of contracts assumed in acquisitions*	47 773	19 316	62 097
Other current liabilities**	157 186	149 935	141 880
Total other current liabilities	**613 012**	**639 016**	**704 197**

* Refer to note 10.

** Other current liabilities include unpaid wages and vacation pay, accrued interest and other provisions.

Note 13 Bonds

(USD 1 000)	**30.09.2018**	**Group** **30.09.2017**	**31.12.2017**
DETNOR02 Senior unsecured bond [1)]	236 259	237 126	230 375
AKERBP – Senior Notes (17/22) [2)]	392 918	388 600	391 664
AKERBP – Senior Notes (18/25) [3)]	493 044	-	-
Long-term bonds	**1 122 220**	**625 726**	**622 039**

[1)] The bond is denominated in NOK and runs from July 2013 to July 2020 and carries an interest rate of 3 month Nibor + 6.5 per cent. The principal falls due on July 2020 and interest is paid on a quarterly basis. The bond is unsecured. The bond has been swapped into USD using a cross currency interest rate swap whereby the group pays Libor + 6.81 per cent quarterly. The financial covenants for this bond are consistent with the RBL as described in note 14.

[2)] The bond was established in July 2017 and carries an interest of 6.0 per cent. The principal falls due in July 2022 and interest is paid on a semi annual basis. The bond is senior unsecured and has no financial covenants.

[3)] The bond was established in March 2018 and carries an interest of 5.875 per cent. The principal falls due in March 2025 and interest is paid on a semi annual basis. The bond is senior unsecured and has no financial covenants.

Note 14 Other interest-bearing debt

(USD 1 000)	30.09.2018	Group 30.09.2017	31.12.2017
Reserve-based lending facility	353 605	1 396 158	1 270 556
Long-term interest-bearing debt	**353 605**	**1 396 158**	**1 270 556**
Bridge facility	1 499 693	-	1 496 374
Short-term interest-bearing debt	**1 499 693**	**-**	**1 496 374**

The RBL facility was established in 2014 and is a senior secured seven-year facility. The facility size amounts to USD 4.0 billion, with an uncommitted accordion option of USD 1.0 billion. The interest rate is from 1 - 6 months LIBOR plus a margin of 2 - 3 per cent based on drawn amount. In addition, a commitment fee is paid on unused credit. The financial covenants are as follows:

- Leverage Ratio shall be maximum 4 until the production start of Johan Sverdrup, thereafter maximum 3.5
- Interest Coverage Ratio shall be minimum 3.5

In relation to the acquisition of Hess Norge AS, the company obtained a new USD 1.5 billion bank facility ("Bridge facility"). The facility has a duration of 18 months, carries an interest of Libor + 1.5 per cent (the margin increases to 2.0 per cent after nine months), and is secured by a pledge in the shares of Aker BP AS (previously Hess Norge AS). The company expects the tax losses from Aker BP AS to be settled during 2018. Such settlement would trigger a mandatory repayment of the USD 1.5 billion bank facility. The financial covenants in this facility are consistent with the RBL.

Note 15 Provision for abandonment liabilities

(USD 1 000)	30.09.2018	Group 30.09.2017	31.12.2017
Provisions as of 1 January	3 043 884	2 156 921	2 156 921
Abandonment liability from acquisitions	-	128 143	1 315 181
Change in abandonment liability due to asset sales	-	-	-207 516
Incurred cost removal	-185 158	-47 310	-74 005
Accretion expense - present value calculation	96 656	97 212	129 619
Change in estimates and incurred liabilities on new drilling and installations	72 850	28 427	-276 315
Total provision for abandonment liabilities	**3 028 232**	**2 363 394**	**3 043 884**
Break down of the provision to short-term and long-term liabilities			
Short-term	140 875	152 668	268 262
Long-term	2 887 356	2 210 726	2 775 622
Total provision for abandonment liabilities	**3 028 232**	**2 363 394**	**3 043 884**

The estimate is based on executing a concept for abandonment in accordance with the Petroleum Activities Act and international regulations and guidelines. The calculations assume an inflation rate of 2.5 per cent and a nominal discount rate before tax of between 3.44 per cent and 4.42 per cent.

Note 16 Contingent liabilities

During the normal course of its business, the group will be involved in disputes, including tax disputes. The group has made accruals for probable liabilities related to litigation and claims based on management's best judgment and in line with IAS 37 and IAS 12.

Note 17 Subsequent events

15 October 2018 the company announced that it has entered into an agreement with Equinor Energy to acquire its 77.8 percent interest in the King Lear gas/condensate discovery in the Norwegian North Sea for a cash consideration of USD 250 million. The transasction is subject to approval by Norwegian authorities.

Note 18 Investments in joint operations

Fields operated:	30.09.2018	30.06.2018
Alvheim	65.000%	65.000 %
Bøyla	65.000%	65.000 %
Hod	90.000%	90.000 %
Ivar Aasen Unit	34.786%	34.786 %
Jette Unit	70.000%	70.000 %
Valhall	90.000%	90.000 %
Vilje	46.904%	46.904 %
Volund	65.000%	65.000 %
Tambar	55.000%	55.000 %
Tambar Øst	46.200%	46.200 %
Ula	80.000%	80.000 %
Skarv	23.835%	23.835 %

Production licences in which Aker BP is the operator:

Licence:	30.09.2018	30.06.2018	Licence:	30.09.2018	30.06.2018
PL 001B	35.000%	35.000 %	PL 762	20.000%	20.000 %
PL 006B	90.000%	90.000 %	PL 777	40.000%	40.000 %
PL 019	80.000%	80.000 %	PL 777B	40.000%	40.000 %
PL 019C	80.000%	80.000 %	PL 777C	40.000%	40.000 %
PL 019E	80.000%	80.000 %	PL 777D	40.000%	40.000 %
PL 026B	90.260%	90.260 %	PL 784	40.000%	40.000 %
PL 027D	100.000%	100.000 %	PL 790	30.000%	30.000 %
PL 028B	35.000%	35.000 %	PL 814	40.000%	40.000 %
PL 033	90.000%	90.000 %	PL 818	40.000%	40.000 %
PL 033B	90.000%	90.000 %	PL 818B	40.000%	40.000 %
PL 036C	65.000%	65.000 %	PL 822S	60.000%	60.000 %
PL 036D	46.904%	46.904 %	PL 839	23.835%	23.835 %
PL 065	55.000%	55.000 %	PL 843	40.000%	40.000 %
PL 065B	55.000%	55.000 %	PL 858	40.000%	40.000 %
PL 088BS	65.000%	65.000 %	PL 861	50.000%	50.000 %
PL 150	65.000%	65.000 %	PL 867	40.000%	40.000 %
PL 159D*	23.835%	0.000 %	PL 868	60.000%	60.000 %
PL 169C	50.000%	50.000 %	PL 869	60.000%	60.000 %
PL 203	65.000%	65.000 %	PL 872	40.000%	40.000 %
PL 203B	65.000%	65.000 %	PL 873	40.000%	40.000 %
PL 212	30.000%	30.000 %	PL 874	90.260%	90.260 %
PL 212B	30.000%	30.000 %	PL 893	60.000%	60.000 %
PL 212E	30.000%	30.000 %	PL 895	60.000%	60.000 %
PL 242	35.000%	35.000 %	PL 906	40.000%	40.000 %
PL 261	50.000%	50.000 %	PL 907	40.000%	40.000 %
PL 262	30.000%	30.000 %	PL 914S	34.786%	34.786 %
PL 300	55.000%	55.000 %	PL 915	35.000%	35.000 %
PL 340	65.000%	65.000 %	PL 916	40.000%	40.000 %
PL 340BS	65.000%	65.000 %	PL 919	65.000%	65.000 %
PL 364	90.260%	90.260 %	PL 932	60.000%	60.000 %
PL 442	90.260%	90.260 %	PL 941	50.000%	50.000 %
PL 442B	90.260%	90.260 %	PL 948	40.000%	40.000 %
PL 460	65.000%	65.000 %	PL 951	40.000%	40.000 %
PL 504	47.593%	47.593 %	PL 963	70.000%	70.000 %
PL 626	60.000%	60.000 %	PL 964	40.000%	40.000 %
PL 659	50.000%	50.000 %			
PL 677	90.000%	90.000 %			
PL 748	50.000%	50.000 %			
PL 748B	50.000%	50.000 %			
Number of licenses in which Aker BP is the operator				**74**	**73**

* Aker BP became the operator of the license during Q3 2018.

Fields non-operated:	30.09.2018	30.06.2018
Atla	10.000%	10.000 %
Enoch	2.000%	2.000 %
Gina Krog	3.300%	3.300 %
Johan Sverdrup	11.573%	11.5733 %
Oda	15.000%	15.000 %
Varg	5.000%	5.000 %

Production licences in which Aker BP is a partner:

Licence:	30.09.2018	30.06.2018
PL 006C	15.000%	15.000 %
PL 006E	15.000%	15.000 %
PL 018DS	13.338%	13.338 %
PL 026	30.000%	30.000 %
PL 029B	20.000%	20.000 %
PL 035	50.000%	50.000 %
PL 035C	50.000%	50.000 %
PL 038	5.000%	5.000 %
PL 048D	10.000%	10.000 %
PL 102C	10.000%	10.000 %
PL 102D	10.000%	10.000 %
PL 102F	10.000%	10.000 %
PL 102G	10.000%	10.000 %
PL 159D*	0.000%	23.835 %
PL 220	15.000%	15.000 %
PL 265	20.000%	20.000 %
PL 272	50.000%	50.000 %
PL 405	15.000%	15.000 %
PL 457BS	40.000%	40.000 %
PL 492	60.000%	60.000 %
PL 502	22.222%	22.222 %
PL 533	35.000%	35.000 %
PL 533B	35.000%	35.000 %
PL 554	30.000%	30.000 %
PL 554B	30.000%	30.000 %
PL 554C	30.000%	30.000 %
PL 554D	30.000%	30.000 %
PL 719	20.000%	20.000 %
PL 721	40.000%	40.000 %
PL 722	20.000%	20.000 %
PL 782S	20.000%	20.000 %
PL 782SB	20.000%	20.000 %
PL 782SC	20.000%	20.000 %
PL 810	30.000%	30.000 %
PL 810B	30.000%	30.000 %
PL 811	20.000%	20.000 %
PL 813	3.300%	3.300 %
PL 838	30.000%	30.000 %
PL 842	30.000%	30.000 %
PL 844	20.000%	20.000 %
PL 852	40.000%	40.000 %
PL 852B	40.000%	40.000 %
PL 852C	40.000%	40.000 %
PL 857	20.000%	20.000 %
PL 862	50.000%	50.000 %
PL 863	40.000%	40.000 %
PL 863B	40.000%	40.000 %
PL 864	20.000%	20.000 %
PL 871	20.000%	20.000 %
PL 891	30.000%	30.000 %
PL 892	30.000%	30.000 %
PL 902	30.000%	30.000 %
PL 942	30.000%	30.000 %
PL 954	20.000%	20.000 %
PL 955	30.000%	30.000 %
PL 961	30.000%	30.000 %
PL 962	20.000%	20.000 %
PL 966	30.000%	30.000 %
Number of licenses in which Aker BP is a partner	**57**	**58**

* Aker BP became the operator of the license during Q3 2018.

Note 19 Results from previous interim reports

	2018			2017				2016
(USD 1 000)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Total income	**999 631**	**974 745**	**889 599**	**725 994**	**596 188**	**594 501**	**646 250**	**655 624**
Production costs	165 466	163 625	173 481	147 076	134 411	121 017	120 874	121 139
Exploration expenses	93 519	75 270	54 661	56 181	63 887	75 375	30 259	44 281
Depreciation	188 525	182 528	185 421	183 138	175 334	184 194	184 004	159 796
Impairments	-	-	-	21 111	1 091	365	29 782	44 627
Other operating expenses	4 334	1 324	3 640	13 549	2 893	3 113	8 051	5 029
Total operating expenses	**451 845**	**422 747**	**417 204**	**421 055**	**377 617**	**384 065**	**372 969**	**374 872**
Operating profit/loss	**547 787**	**551 998**	**472 395**	**304 940**	**218 571**	**210 436**	**273 280**	**280 752**
Net financial items	-57 869	-21 778	-46 954	-56 526	-9 469	-83 597	-46 508	-70 572
Profit/loss before taxes	**489 918**	**530 220**	**425 442**	**248 413**	**209 102**	**126 840**	**226 772**	**210 180**
Taxes (+)/tax income (-)	365 047	394 219	264 197	214 377	97 065	66 944	157 955	277 183
Net profit/loss	**124 871**	**136 001**	**161 245**	**34 036**	**112 037**	**59 896**	**68 818**	**-67 003**

Alternative performance measures

Aker BP may disclose alternative performance measures as part of its financial reporting as a supplement to the financial statements prepared in accordance with IFRS. Aker BP believes that the alternative performance measures provide useful supplemental information to management, investors, security analysts and other stakeholders and are meant to provide an enhanced insight into the financial development of Aker BP's business operations and to improve comparability between periods.

Depreciation per boe is depreciation divided by number of barrels of oil equivalents produced in the corresponding period

Dividend per share (DPS) is dividend paid in the quarter divided by number of shares outstanding

EBIT is short for earnings before interest and other financial items and taxes

EBITDA is short for earnings before interest and other financial items, taxes, depreciation and amortisation and impairments

EBITDAX is short for earnings before interest and other financial items, taxes, depreciation and amortisation, impairments and exploration expenses

Equity ratio is total equity divided by total assets

Net interest-bearing debt is book value of current and non-current interest-bearing debt less cash and cash equivalents

Production cost per boe is production cost divided by number of barrels of oil equivalents produced in the corresponding period

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