Second Quarter 2018

QUARTERLY REPORT
FOR AKER BP ASA

SUMMARY OF THE QUARTER

Aker BP ASA ("the company" or "Aker BP") reports total income of USD 975 million and operating profit of USD 552 million for the second quarter 2018. Net profit was USD 136 million and earnings per share were USD 0.38. The company paid a dividend of USD 0.3124 (NOK 2.51718) per share in the quarter.

The company's net production in the second quarter was 157.8 (142.7) thousand barrels of oil equivalents per day ("mboepd"). The increase was primarily a result of the acquisition of Hess Norge in December 2017. The company remains on track to reach its full-year production estimate of 155-160 mboepd.

Revenues were positively impacted by increased oil and gas prices. Average realised prices were USD 76 (51) per barrel of oil, and USD 0.28 (0.18) per standard cubic metre ("scm") of natural gas.

Production costs amounted to USD 164 (121) million or USD 11.4 (9.3) per barrel oil equivalents ("boe"). For the first six months, production cost per boe averaged USD 11.8, and remains in line with the company's estimate of USD 12 per boe for the full year.

Exploration expenses amounted to USD 75 (75) million. One exploration well was drilled in the quarter, which resulted in a non-commercial discovery. Exploration expenses were also impacted by two seismic surveys in the Barents Sea. Total exploration spend for 2018 is now estimated to be USD 425 (previously 350) million due to increased activity following the Frosk discovery and recent license awards.

Operating profit (EBIT) was USD 552 (210) million, after depreciation of USD 183 (184) million or USD 12.7 (14.2) per boe. Net financial expenses were USD 22 (84) million, while taxes amounted to USD 395 (67) million. Net profit was USD 136 (60) million for the second quarter.

Investments in fixed assets amounted to USD 302 (271) 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 remains unchanged at around USD 1.3 billion.

Abandonment expenditures were USD 72 (20) million, driven by the ongoing campaign to plug and abandon old wells on the Valhall field. The abandonment program has progressed ahead of plan, and the rig will in the fourth quarter be re-allocated to production drilling. The total estimated abandonment spend for 2018 has consequently been reduced to USD 250 (previously 350) million.

The company's net interest-bearing debt was USD 3.0 billion at the end of the second quarter. Total available liquidity was USD 3.6 billion.

In May, the company paid a quarterly dividend of USD 112.5 million or USD 0.3124 per share, and the Board of directors has resolved to pay the same dividend in August. The plan is to maintain this level for the remainder of 2018, implying total annual dividends of USD 450 million. The Board's ambition is to increase the annual dividends by USD 100 million per year until 2021.

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	Q2 2018	Q2 2017	2018 YTD	2017 YTD
Operating income	USDm	975	595	1 864	1 241
EBITDA	USDm	735	395	1 392	882
Net result	USDm	136	60	297	129
Earnings per share (EPS)	USD	0.38	0.18	0.83	0.38
Production cost per barrel	USD/boe	11.4	9.3	11.8	9.3
Depreciation per barrel	USD/boe	12.7	14.2	12.8	14.1
Cash flow from operations	USDm	613	447	1 214	882
Cash flow from investments	USDm	-403	-312	-781	-582
Total assets	USDm	12 147	9 331	12 147	9 331
Net interest-bearing debt	USDm	2 968	2 302	2 968	2 302
Cash and cash equivalents	USDm	49	66	49	66

SUMMARY OF PRODUCTION

	Unit	Q2 2018	Q2 2017	2018 YTD	2017 YTD
Alvheim (65%)	boepd	40 091	61 788	40 303	63 078
Bøyla (65%)	boepd	3 265	4 935	3 250	4 741
Gina Krog (3.3%)	boepd	1 848	-	1 677	-
Hod (90%) (37.5% in 2017)	boepd	1 063	580	1 039	574
Ivar Aasen (34.8%)	boepd	23 699	17 257	24 058	16 136
Skarv (23.8%)	boepd	27 579	29 326	27 336	30 461
Tambar / Tambar East (55.0%/46.2%)	boepd	5 398	2 621	3 515	2 341
Ula (80%)	boepd	5 361	7 232	5 920	6 710
Valhall (90%) (36% in 2017)	boepd	32 670	13 080	33 083	13 933
Vilje (46.9%)	boepd	4 098	5 795	4 591	5 700
Volund (65%)	boepd	12 646	4	13 373	264
Other	boepd	67	95	69	80
SUM	**boepd**	**157 784**	**142 713**	**158 214**	**144 018**
Oil price	USD/bbl	76	51	73	53
Gas price	USD/scm	0.28	0.18	0.28	0.20

FINANCIAL REVIEW

Income statement

(USD million)	Q2 2018	Q2 2017
Operating income	975	595
EBITDA	735	395
EBIT	552	210
Pre-tax profit/loss	530	127
Net profit	136	60
EPS (USD)	0.38	0.18

Statement of financial position

(USD million)	Q2 2018	Q2 2017
Goodwill	1 860	1 817
PP&E	5 835	4 725
Cash & cash equivalents	49	66
Total assets	12 147	9 331
Equity	3 064	2 453
Interest-bearing debt	3 017	2 368

Total income in the second quarter was USD 975 (595) million, higher than the second quarter 2017 due to increased production and higher realized prices. Petroleum revenues amounted to USD 978 (590) million, while other income was USD -3 (4) million, primarily related to realized and unrealized gains and losses on commodity hedges.

Exploration expenses amounted to USD 75 (75) million in the quarter, reflecting the Svanefjell well which resulted in a non-commercial discovery, in addition to seismic costs, field evaluation costs, area fees and other exploration expenses. Production costs were USD 164 (121) million, equating to 11.4 (9.3) USD/boe. The higher production costs compared to the second quarter 2017 are mainly a result of the increased interest in Valhall and Hod, and by a generally higher activity level. Other operating expenses amounted to USD 1 (3) million.

Depreciation amounted to USD 183 (184) million, corresponding to 12.7 (14.2) USD/boe. No impairments were recorded in the quarter, compared to USD 0.4 million in the second quarter 2017.

The company recorded operating profit of USD 552 (210) million, higher than the second quarter 2017, mainly driven by increased production and higher realized prices.

Net profit for the period was USD 136 (60) million after net financial expenses of USD 22 (84) million and tax expenses of USD 394 (67) million, or 74 (53) percent. Earnings per share were USD 0.38 (0.18).

At the end of second quarter 2018, total intangible assets amounted to USD 3,847 (3,444) million, of which goodwill was USD 1,860 (1,817) million.

Property, plant and equipment increased to USD 5,835 (4,725) million, primarily as a result of 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 1,596 (402) 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 second half of 2018.

Cash and cash equivalents were USD 49 (66) million at the end of the quarter. Total assets were USD 12,147 (9,331) million.

Equity amounted to USD 3,064 (2,453) million at the end of the second quarter, corresponding to an equity ratio of 25 (26) percent. The increase was caused by total comprehensive income of USD 472 million and an equity issue with net proceeds of USD 489 million adjusted for USD 350 million in dividend payments in the period from 1 July 2017 to 30 June 2018.

Deferred tax liabilities amounted to USD 1,525 (1,125) million and are detailed in note 7 to the financial statements.

Gross interest-bearing debt was USD 3,017 (2,368) million, consisting of the DETNOR02 bond of USD 234 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 399 million and a bank term loan of USD 1,499 million. The latter will be repaid when the previously mentioned tax loss from Hess Norge is disbursed

Cash flow

(USD million)	Q2 2018	Q2 2017
Cash flow from operations	613	447
Cash flow from investments	-403	-312
Cash flow from financing	-178	-253
Net change in cash & cash eq.	33	-118
Cash and cash eq. EOQ	49	66

Net cash flow from operating activities was USD 613 (447) million in the second quarter. The change was mainly caused by increased profit before tax, which was driven by increased production and higher realized prices.

Net cash flow to investment activities was USD 403 (312) million, of which investments in fixed assets amounted to USD 302 (271) million for the quarter, mainly related to Johan Sverdrup and Valhall. Investments in intangible assets including capitalized exploration were USD 29 (21) million in the quarter. Payments for decommissioning activities amounted to USD 72 (20) million in the quarter, mainly related to plugging and abandonment of depleted wells at Valhall.

Net cash flow to financing activities was USD -178 (-253) million, reflecting debt repayment of USD 65 million and dividend disbursements of USD 112.5 million during the quarter.

Funding

At the end of the second quarter, the company had total available liquidity of USD 3.6 (2.7) billion, comprising of cash and cash equivalents of USD 49 (66) million and undrawn credit facilities of USD 3,550 (2,605) million.

Bondholders representing NOK 1.9 million nominal worth of DETNOR02 bonds exercised the distribution put option following the dividend payment in May. Aker BP consequently owns DETNOR02 bonds equal to NOK 7.7 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.

The company has bought Brent put options for 2018 at strike prices from USD 50 to USD 60 per barrel. Total hedging volume is around 22 percent of estimated oil production for 2018, corresponding to approximately 78 percent of the undiscounted after-tax value.

The company has also started to hedge oil production for 2019 by buying put options at strike price USD 55 per barrel for 10 percent of the estimated oil production for the first half of 2019, corresponding to approximately 35 percent of the undiscounted after-tax value.

Dividends

A quarterly dividend of USD 112.5 million, corresponding to USD 0.3124 per share was disbursed on 22 May 2018.

At the Annual General Meeting in April 2018, the Board was authorized to approve the distribution of dividends based on the company's annual accounts for 2017 pursuant to section 8-2 (2) of the Norwegian Public Limited Companies Act.

The Board has proposed an annual dividend of USD 450 million in 2018 and stated a clear ambition to increase this by USD 100 million per year until 2021.

On 12 July 2018, the Board of Directors declared a quarterly dividend of USD 0.3124 per share, to be disbursed on or about 9 August 2018.

OPERATIONAL REVIEW

Aker BP produced 14.4 (13.0) mmboe in the second quarter of 2018, corresponding to 157.8 (142.7) mboepd. The average realized oil price was USD 76 (51) per barrel, while the average realized gas price was USD 0.28 (0.18) 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.

Second quarter production from the Alvheim area was 60.1 mboepd net to Aker BP, down five percent from the previous quarter due to ordinary decline and a planned inspection of one inlet separator. Two new wells at the Boa drill centre started production in the first quarter 2018 and contributed positively to production volumes in the second quarter.

The production efficiency for the Alvheim area was 95 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).

Second quarter production from the Valhall area was 33.7 mboepd net to Aker BP. This represents a two percent reduction from the previous quarter. The first two wells of the 2018 IP drilling program have been successfully drilled, but production start was delayed due to technical challenges with the drilling and stimulation operations, and is now expected to take place during the third quarter. The third IP well is expected to be drilled by the end of the year. Production was also affected by a planned maintenance shut down in June.

The Maersk Invincible rig has continued the successful P&A campaign at Valhall.

The production efficiency for the Valhall area was 85 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. Production from the Oselvar tie-back ceased on 1 April 2018 in accordance with agreement.

Second quarter production from the Ula area was 10.8 mboepd net to Aker BP, 33 percent higher than the previous quarter due to start-up of the two new Tambar wells during the first quarter. This was partly offset by a planned shut-down in June for modifications relating to tie-in of the Oda field, some equipment reliability issues on Tambar and well reliability issues on Ula.

One of Ula's four Water Alternating Gas ("WAG") injector wells has been temporarily shut-in due to technical issues, but in general production on Ula has been stable.

The production efficiency for the Ula area was 66 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.

Second quarter production from the Skarv area was 27.6 mboepd net to Aker BP, two percent higher than in the previous quarter. At the beginning of the second quarter two wells were shut in. During the quarter, one of the wells was repaired and put on production, while the Xmas tree from the second well was recovered for root cause analysis and repairs.

During the second quarter an additional well was shut in due to what appears to be a similar issue with the Xmas tree. Skarv also experienced issues with the gas injection system, however the impact on production was minimal due to quick and efficient repairs combined with other mitigating actions.

The production efficiency for the Skarv area was 88 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 23.7 mboepd net to Aker BP in the second quarter, three percent below the previous quarter. The average plant availability of Ivar Aasen was 93 percent in the period, down from 98 percent previous quarter. The reduction in efficiency was related to a planned shutdown test and to drilling activity. Production was also negatively impacted by Edvard Grieg availability due to power generation issues, resulting in a production efficiency of 90 percent.

Two new water injectors were successfully completed in the second quarter, and drilling of the Hanz appraisal well, which will also target the Slengfehøgda exploration prospect, commenced on 30 June.

Gina Krog

PL029B/029C/048/303 (partner)

The Gina Krog field (3.3 percent) started production on 30 June 2017. The field has been developed with a fixed platform with living quarters and processing facilities. The oil from Gina Krog is exported by shuttle tankers while gas is exported via the Sleipner platform.

Production from Gina Krog was 1.8 mboepd net to Aker BP in the second 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	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Total recordable injuries frequency (TRIF)	Per mill. exp. hours	4.2	1.9	5.3	0.7	0.7	5.4
Serious incident frequency (SIF)	Per mill. exp. hours	0.6	1.3	0.7	0.7	0.7	2.7
Loss of primary containment (LOPC)	Count	0	1	1	0	0	0
Process safety events Tier 1 and 2	Count	1	1	1	0	0	0
CO2 emissions intensity	Kg CO2/boe	6.8	7.4	7.0	7.4	7.0	6.7

In May 2018, the Petroleum Safety Authority Norway ("PSA") issued its investigation report of the fatal incident that took place on Maersk Interceptor on the Tambar field on 7 December 2017. Both Aker BP and Maersk Drilling support the findings of the PSA report, which are consistent with those of the internal Maersk Drilling investigation. Both companies will continue to share the learnings in relevant industry forums.

PROJECTS

Johan Sverdrup Unit

PL265/501/502 (partner)

Phase 1 of the Johan Sverdrup (11.5733 percent) development project is progressing according to plan towards production start-up by the end of 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 second quarter, approximately 87 percent of the Phase 1 facilities were complete. Early June the 22,000 tonne topside for the drilling platform was lifted into position offshore in one single lift by Allsea's Pioneering Spirit, the world's biggest heavy-lift vessel. The Johan Sverdrup partners are the first users in the world of this ground-breaking technology. The second of four platforms in the first development phase of the giant Johan Sverdrup field is thus installed. Also, the power cables to the field from shore were rolled in June, and the installation of Norway's biggest oil export pipeline from Mongstad to the field is well under way.

After a successful completion of the eight pre-drilled production wells and a four well pilot/appraisal campaign for further improvement of reservoir definition, 10 pre-drilled water injection wells have been completed.

PDO for Phase 2 is scheduled for the second half of 2018. Phase 2 production start-up is expected in 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, increasing the capacity from 440,000 to 660,000 barrels of oil per day. In April, a Letter of Intent was signed with Aibel for construction of the processing platform topside for phase 2 of the project. A letter of intent for field centre modifications was also signed with a joint venture of Aker Solutions and Kværner.

Phase 2 also 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.

The operator's Phase 1 CAPEX estimate, last updated in the first quarter 2018, was NOK 88 billion (nominal at project currency), which is NOK 35 billion (28 percent) lower than at the time the PDO was submitted in 2015. The CAPEX for Phase 2 is estimated to below NOK 45 billion, which is approximately half the cost estimated for Phase 2 when the PDO for Phase 1 was submitted.

The operator estimates the Johan Sverdrup reserves to be between 2.1 and 3.1 billion barrels of oil equivalents ("boe") and the full field break-even oil price to be below USD 20 per boe.

Valhall Flank West

PL006B/033/033B (operator)

The Valhall Flank West project (90 percent) 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. Engineering of the topside and jacket is approaching completion while the NUI cellar deck is under construction in Verdal, Norway. An offshore campaign was recently performed to prepare the Valhall area for subsea installation activities in 2019 while modifications at the Valhall field centre are well underway.

Valhall Flank North Water Injection

PL006B/033/033B (operator)

The Valhall Flank North Water Injection project (90 percent) 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 combined with offshore wind. 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.

The company is targeting a concept selection in 2018.

Skogul

PL460 (operator)

Skogul (65 percent) 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 (23.8 percent) 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 from the new wells is planned to begin late 2020.

Field development contracts have been entered into with Subsea 7 for Subsea Umbilical Riser Flowline ("SURF") and with Aker Solutions for Subsea Production System ("SPS"). The project is progressing as planned and fabrication activities have started at the Aker Solutions yard in Sandnessjøen, Norway.

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. Gas lift is scheduled to commence in the fourth quarter pending completion of the remaining facilities modifications.

Hod Development

PL033 (operator)

The original Hod field (90 percent) comprises the three reservoir structures Hod West, Hod East and Hod Saddle. Hod was the first unmanned platform in the Norwegian North Sea, tied back to the Valhall field centre through a 13 kilometres long flowline. The field originally started production in 1990. The Hod Development Project aims to redevelop the field to recover the remaining 64 mmboe gross resources in Hod through a new 12 slot Unmanned Installation (UI), as well as performing exploration and appraisal drilling that may include HP/HT wells and/or more well slots.

A Hod appraisal well is planned to be drilled next year, followed by concept selection planned in third quarter 2019.

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 2019.

EXPLORATION

During the quarter, the company's cash spending on exploration was USD 86 million. USD 75 million was recognized as exploration expenses in the period, relating to seismic, area fees, field evaluations and G&G costs.

On 18 June 2018, the Norwegian Ministry of Petroleum and Energy announced the results of the 24th licensing round. Aker BP was awarded six licenses, of which two were as operator. All the new licenses are in the Barents Sea.

Drilling of the Svanefjell prospect in PL659 (Aker BP 50%) was completed in May. The well proved gas in the upper Triassic reservoir, estimated to 2.0–3.5 billion standard cubic metres recoverable gas. The discovery is not likely to be of commercial value, but traces of oil were observed in the reservoir, providing important information for further exploration in the area.

In the Alvheim area the appraisal campaign was started with the drilling of top hole. The rig has moved to the Kameleon field for production drilling, and will then return to Gekko.

The previously announced agreement with Fortis Petroleum Norway AS to acquire its working interests in PL869 (20 percent) near the Frosk discovery, PL677 (30 percent) near the Vilje field and PL626 (10 percent) near the Hanz field, was completed in the second quarter.

REPORT FOR THE FIRST HALF 2018

	Unit	Per 30 June 2018	Per 30 June 2017
Oil and gas production	mboepd	158.2	144.0
Oil price	USD/bbl	73	53
Operating income	USDm	1 864	1241
EBITDA	USDm	1 392	882
Net result	USDm	297	129
Net interest-bearing debt	USDm	2 968	2302

During the first six months of 2018, the company reported consolidated revenues of USD 1,864 (1,241) million. Production in the period was 158.2 (144.0) thousand barrels of oil equivalent per day ("mboepd"). Average realised prices were USD 73 (53) per barrel of oil and USD 0.28 (0.20) per standard cubic metre of natural gas. The growth in production came from the increased interest in Valhall and Hod following the acquisition of Hess Norway late 2017, the Volund field with two new production wells, and the Ivar Aasen field which has now reached full capacity.

Production costs were USD 337 (242) million, or USD 11.8 (9.3) per barrel of oil equivalents. Overall the increase was driven by higher production activity. The increase in unit cost was caused by the increased interest in Valhall and Hod fields, which operate at a higher unit cost than the average of the company's portfolio.

Exploration expenses amounted to USD 130 (106) million. Aker BP participated in four exploration wells during the first half of 2018. Drilling of the Frosk prospect in PL340 near Alvheim resulted in an oil discovery estimated to contain 30-60 mmboe. The Raudåsen prospect in PL790 was dry. The Kvitungen Tumler prospect in PL839 near Skarv was dry, however the wellbore also appraised the Ærfugl reservoir with positive results. An exploration well on the Svanefjell prospect in PL659 in the Barents Sea found gas and traces of oil, however the discovery was classified as non-commercial.

EBITDA amounted to USD 1,392 (882) million in the period and EBIT was USD 1,024 (484) million. Net profit for the first half of 2018 was USD 297 (129) million, translating into an EPS of USD 0.83 (0.38).

Cash flow to investments amounted to USD 781 (582) million. The Johan Sverdrup field development progressed as planned, and remains on track for production start in the second half of 2019. The company also made significant investments in other development projects across its portfolio.

On 15 March, the company priced a notes offering of USD 500 million aggregate principal amount of 5.875% senior notes due 2025 at par. Interest will be payable semi-annually. The offering was closed on 22 March 2018.

As at 30 June 2018, the company had net interest-bearing debt of USD 2,968 (2,302) million. Available liquidity was USD 3.6 (2.7) billion. comprising of cash and cash equivalents of USD 49 (66) million and undrawn credit facilities of USD 3,550 (2,605) million.

In January 2018, Aker BP was awarded 23 licenses in the 2017 APA (Awards in Predefined Areas) round, of which 14 as operator. In June 2018, the company was awarded six licenses in the 24th licencing round, of which two as operator.

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. Total Recordable Injuries Frequency ("TRIF") for the first half 2018 was 3.0 (2.8).

RISKS AND UNCERTAINTY

Investment in Aker BP involves risks and uncertainties as described in the company's annual report for 2017.

As an oil and gas company operating on the Norwegian Continental Shelf, exploration results, reserve and resource estimates and estimates for capital and operating expenditures are associated with uncertainty. The field's production performance may be uncertain over time.

The company is exposed to various forms of financial risks, including, but not limited to, fluctuation in oil prices, exchange rates, interest rates and capital requirements; these are described in the company's annual report and accounts, and in note 28 to the accounts for 2017. The company is also exposed to uncertainties relating to the international capital markets and access to capital and this may influence the speed with which development projects can be accomplished.

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 expects a production level of 155-160 mboepd with a production cost of approximately 12 USD/boe, and capex is expected to be around USD 1.3 billion, in line with previous estimates.

The company will have four to five rigs in operation in the second half of 2018, performing drilling of production and exploration wells as well as maintenance activities and plugging operations. In total, Aker BP currently plans to participate in 12 exploration wells in 2018. The exploration plan is subject to continuous optimization.

Exploration spend for 2018 is estimated to be approximately USD 425 million. This represents an increase of USD 75 million compared to previous estimates due to increased activity following the Frosk discovery and recent license awards.

Abandonment spend for 2018 is estimated to be approximately USD 250 million, down USD 100 million compared to previous estimates due to accelerated execution of the campaign to plug and abandon old wells at Valhall.

A quarterly dividend of USD 0.3124 per share is scheduled to be paid in August. Planned total dividend payments in 2018 amount to USD 450 million. The board's intention is to increase the dividend level by USD 100 million each year until 2021.

Financial statements with notes

INCOME STATEMENT (Unaudited)

		Group			
		Q2		01.01.-30.06.	
(USD 1 000)	**Note**	**2018**	**2017**	**2018**	**2017**
Petroleum revenues		977 933	590 471	1 869 578	1 237 642
Other operating income		-3 187	4 031	-5 233	3 109
Total income	2	**974 745**	**594 501**	**1 864 345**	**1 240 751**
Production costs		163 625	121 017	337 106	241 891
Exploration expenses	3	75 270	75 375	129 931	105 634
Depreciation	5	182 529	184 194	367 950	368 198
Impairments	4, 5	-	365	-	30 147
Other operating expenses		1 324	3 113	4 965	11 164
Total operating expenses		**422 747**	**384 065**	**839 951**	**757 034**
Operating profit/loss		**551 998**	**210 436**	**1 024 394**	**483 717**
Interest income		6 001	1 085	10 905	2 159
Other financial income		50 777	15 384	56 970	30 230
Interest expenses		30 651	31 259	63 326	61 267
Other financial expenses		47 905	68 806	73 280	101 227
Net financial items	6	**-21 778**	**-83 597**	**-68 732**	**-130 105**
Profit/loss before taxes		**530 220**	**126 840**	**955 662**	**353 612**
Taxes (+)/tax income (-)	7	394 219	66 944	658 417	224 898
Net profit/loss		**136 001**	**59 896**	**297 246**	**128 714**
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/loss(-) USD per share		0.38	0.18	0.83	0.38

STATEMENT OF COMPREHENSIVE INCOME

		Group			
		Q2		01.01.-30.06.	
(USD 1 000)	**Note**	**2018**	**2017**	**2018**	**2017**
Profit/loss for the period		136 001	59 896	297 246	128 714
Items which may be reclassified over profit and loss (net of taxes)					
Currency translation adjustment		-70 269	-	2 863	-356
Total comprehensive income in period		**65 732**	**59 896**	**300 108**	**128 358**

STATEMENT OF FINANCIAL POSITION (Unaudited)

		Group		
(USD 1 000)	Note	30.06.2018	30.06.2017	31.12.2017
ASSETS				
Intangible assets				
Goodwill	5	1 860 126	1 817 486	1 860 126
Capitalized exploration expenditures	5	401 069	344 268	365 417
Other intangible assets	5	1 585 358	1 282 600	1 617 039
Tangible fixed assets				
Property, plant and equipment	5	5 835 137	4 724 803	5 582 493
Financial assets				
Long-term receivables		37 849	44 107	40 453
Long-term derivatives	11	-	7 398	12 564
Other non-current assets		8 612	23 643	8 398
Total non-current assets		**9 728 151**	**8 244 305**	**9 486 491**
Inventories				
Inventories		80 438	64 867	75 704
Receivables				
Accounts receivable		134 629	101 441	99 752
Tax receivables	7	1 595 916	401 857	1 586 006
Other short-term receivables	8	529 160	446 493	535 518
Short-term derivatives	11	29 377	6 149	2 585
Cash and cash equivalents				
Cash and cash equivalents	9	49 245	65 569	232 504
Total current assets		**2 418 765**	**1 086 377**	**2 532 069**
TOTAL ASSETS		**12 146 916**	**9 330 683**	**12 018 560**

STATEMENT OF FINANCIAL POSITION (Unaudited)

(USD 1 000)	Note	Group 30.06.2018	30.06.2017	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		-630 648	-752 351	-705 756
Total equity		**3 063 704**	**2 452 565**	**2 988 596**
Non-current liabilities				
Deferred taxes	7	1 525 004	1 124 750	1 307 148
Long-term abandonment provision	15	2 852 795	2 109 309	2 775 622
Provisions for other liabilities	10	130 240	196 541	152 418
Long-term bonds	13	1 119 027	223 523	622 039
Long-term derivatives	11	9 295	24 315	13 705
Other interest-bearing debt	14	399 255	1 814 053	1 270 556
Current liabilities				
Short-term bonds	13	-	330 000	-
Trade creditors		82 148	75 090	32 847
Accrued public charges and indirect taxes		21 324	22 882	27 949
Tax payable	7	687 328	224 957	351 156
Short-term derivatives	11	10 012	-	7 691
Short-term abandonment provision	15	168 956	112 907	268 262
Short-term interest-bearing debt	14	1 499 079	-	1 496 374
Other current liabilities	12	578 749	619 789	704 197
Total liabilities		**9 083 212**	**6 878 117**	**9 029 964**
TOTAL EQUITY AND LIABILITIES		**12 146 916**	**9 330 683**	**12 018 560**

STATEMENT OF CHANGES IN EQUITY - GROUP (Unaudited)

			Other equity					
				Other comprehensive income				
(USD 1 000)	**Share capital**	**Share premium**	Other paid-in capital	Actuarial gains/(losses)	Foreign currency translation reserves	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	-	-	-	-	-	-112 500	-112 500	-112 500
Profit/loss for the period	-	-	-	-	-	161 245	161 245	161 245
Other comprehensive income for the period	-	-	-	-	73 132	-	73 132	73 132
Equity as of 31.03.2018	**57 056**	**3 637 297**	573 083	-89	-17 251	-1 139 622	**-583 879**	**3 110 473**
Dividend distributed	-	-	-	-	-	-112 500	-112 500	-112 500
Profit/loss for the period	-	-	-	-	-	136 001	136 001	136 001
Other comprehensive income for the period	-	-	-	-	-70 269	-	-70 269	-70 269
Equity as of 30.06.2018	**57 056**	**3 637 297**	573 083	-89	-87 521	-1 116 121	**-630 648**	**3 063 704**

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

STATEMENT OF CASH FLOW (Unaudited)

		Group				
		Q2		01.01.-30.06.		Year
(USD 1 000)	Note	2018	2017	2018	2017	2017
CASH FLOW FROM OPERATING ACTIVITIES						
Profit/loss before taxes		530 220	126 840	955 662	353 612	811 128
Taxes paid during the period	7	-69 086	-	-103 466	-	-101 115
Tax refund during the period		-	-	-	-	404 704
Depreciation	5	182 529	184 194	367 950	368 198	726 670
Net impairment losses	4, 5	-	365	-	30 147	52 349
Accretion expenses	6, 15	33 006	32 742	65 152	64 456	129 619
Interest expenses	6	48 956	44 874	93 507	86 040	156 704
Interest paid		-36 381	-45 614	-87 537	-86 770	-145 940
Changes in derivatives	2, 6	-9 611	-17 766	-16 317	-29 939	-34 461
Amortized loan costs	6	7 594	10 520	15 719	17 663	36 900
Amortization of fair value of contracts	10	14 189	8 155	28 384	8 155	11 728
Expensed capitalized dry wells	3, 5	17 997	34 562	31 662	35 621	75 401
Changes in inventories, accounts payable and receivables		-66 256	42 217	9 691	36 499	-7 583
Changes in other current balance sheet items		-39 781	25 600	-146 635	-1 517	39 387
NET CASH FLOW FROM OPERATING ACTIVITIES		**613 376**	**446 691**	**1 213 770**	**882 165**	**2 155 491**
CASH FLOW FROM INVESTMENT ACTIVITIES						
Payment for removal and decommissioning of oil fields	15	-72 307	-20 282	-154 210	-27 966	-85 733
Disbursements on investments in fixed assets		-301 508	-271 105	-558 265	-503 512	-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	-28 775	-20 547	-68 235	-50 451	-111 724
NET CASH FLOW USED IN INVESTMENT ACTIVITIES		**-402 591**	**-311 934**	**-780 710**	**-581 929**	**-3 058 994**
CASH FLOW FROM FINANCING ACTIVITIES						
Repayment of long-term debt		-65 252	-190 000	-880 252	-225 470	-777 911
Repayment of bond (DETNOR03)		-	-	-	-	-330 000
Net cash received from issuance of new shares		-	-	-	-	489 436
Net proceeds from issuance of debt		-	-	492 423	-	1 886 885
Paid dividend		-112 500	-62 500	-225 000	-125 000	-250 000
NET CASH FLOW FROM FINANCING ACTIVITIES		**-177 752**	**-252 500**	**-612 829**	**-350 470**	**1 018 410**
Net change in cash and cash equivalents		**33 033**	**-117 743**	**-179 769**	**-50 234**	**114 906**
Cash and cash equivalents at start of period		37 999	182 795	232 504	115 286	115 286
Effect of exchange rate fluctuation on cash held		-21 787	517	-3 491	517	2 312
CASH AND CASH EQUIVALENTS AT END OF PERIOD	9	**49 245**	**65 569**	**49 245**	**65 569**	**232 504**
SPECIFICATION OF CASH EQUIVALENTS AT END OF PERIOD						
Bank deposits and cash		49 245	57 069	49 245	57 069	231 506
Restricted bank deposits		-	8 501	-	8 501	998
CASH AND CASH EQUIVALENTS AT END OF PERIOD	9	**49 245**	**65 569**	**49 245**	**65 569**	**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 12 July 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 princples 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			
	Q2		01.01.-30.06.	
Breakdown of petroleum revenues (USD 1 000)	**2018**	**2017**	**2018**	**2017**
Sales of liquids	782 805	607 302	1 587 506	1 079 877
Sales of gas	140 926	82 976	280 395	177 181
Tariff income	4 622	5 316	9 602	10 970
Total petroleum sales	**928 353**	**695 593**	**1 877 503**	**1 268 028**
Impact from change in over/underlift balances of liquids	49 580	-105 122	-7 925	-30 386
Total petroleum revenues	**977 933**	**590 471**	**1 869 578**	**1 237 642**

Breakdown of produced volumes (barrels of oil equivalent)				
Liquids	11 176 206	10 071 954	22 302 135	20 352 340
Gas	3 182 150	2 914 916	6 334 646	5 714 938
Total produced volumes	**14 358 356**	**12 986 870**	**28 636 782**	**26 067 278**

Other income (USD 1 000)				
Realized gain/loss (-) on oil derivatives	-3 946	-1 053	-7 432	-3 601
Unrealized gain/loss (-) on oil derivatives	-3 429	4 016	-2 320	5 407
Gain on license transactions	-	556	-	556
Other income	4 188	511	4 520	748
Total other income	**-3 187**	**4 031**	**-5 233**	**3 109**

Note 3 Exploration expenses

Breakdown of exploration expenses (USD 1 000)	Group			
	Q2		01.01.-30.06.	
	2018	2017	2018	2017
Seismic	30 033	17 418	43 512	27 807
Area fee	2 330	3 264	6 576	8 572
Field Evaluation	14 580	11 239	29 038	17 888
Dry well expenses*	17 997	34 562	31 662	35 621
Other exploration expenses	10 329	8 891	19 143	15 746
Total exploration expenses	**75 270**	**75 375**	**129 931**	**105 634**

* Mainly related to the Svanefjell well

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 Q2 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	215 647	30 324	5 416	251 387
Disposals	-	-	-	-
Reclassification*	-157 741	149 883	7 859	-
Acquisition cost 31.03.2018	**1 538 594**	**6 238 007**	**117 621**	**7 894 222**
Accumulated depreciation and impairments 31.12.2017	**-**	**2 025 004**	**35 338**	**2 060 342**
Depreciation	-	164 444	4 675	169 119
Impairment	-	-	-	-
Retirement/transfer depreciations	-	-	-	-
Accumulated depreciation and impairments 31.03.2018	**-**	**2 189 447**	**40 013**	**2 229 461**
Book value 31.03.2018	**1 538 594**	**4 048 560**	**77 607**	**5 664 761**
Acquisition cost 31.03.2018	**1 538 594**	**6 238 007**	**117 621**	**7 894 222**
Additions	308 547	27 283	774	336 605
Disposals	-	-	-	-
Reclassification	-20 579	21 521	-20	922
Acquisition cost 30.06.2018	**1 826 562**	**6 286 811**	**118 375**	**8 231 748**
Accumulated depreciation and impairments 31.03.2018	**-**	**2 189 447**	**40 013**	**2 229 461**
Depreciation	-	162 493	4 657	167 150
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**

* The reclassification is mainly related to infill wells on Boa and Tambar fields

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	-	-	-	39 460	-
Disposals/expensed dry wells	-	-	-	13 665	-
Reclassification	-	-	-	-	-
Acquisition cost 31.03.2018	**1 933 241**	**7 501**	**1 940 742**	**391 212**	**2 738 973**
Accumulated depreciation and impairments 31.12.2017	**316 236**	**7 467**	**323 703**	**-**	**878 847**
Depreciation	16 298	4	16 302	-	-
Impairment	-	-	-	-	-
Retirement/transfer depreciations	-	-	-	-	-
Accumulated depreciation and impairments 31.03.2018	**332 534**	**7 472**	**340 006**	**-**	**878 847**
Book value 31.03.2018	**1 600 707**	**30**	**1 600 736**	**391 212**	**1 860 126**
Acquisition cost 31.03.2018	**1 933 241**	**7 501**	**1 940 742**	**391 212**	**2 738 973**
Additions	-	-	-	28 775	-
Disposals/expensed dry wells	-	-	-	17 997	-
Reclassification	-	-	-	-922	-
Acquisition cost 30.06.2018	**1 933 241**	**7 501**	**1 940 742**	**401 069**	**2 738 973**
Accumulated depreciation and impairments 31.03.2018	**332 534**	**7 472**	**340 006**	**-**	**878 847**
Depreciation	15 374	4	15 378	-	-
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**

	Group			
	Q2		01.01.-30.06.	
Depreciation in the income statement (USD 1 000)	2018	2017	2018	2017
Depreciation of tangible fixed assets	167 150	159 975	336 269	319 600
Depreciation of intangible assets	15 378	24 219	31 681	48 598
Total depreciation in the income statement	**182 529**	**184 194**	**367 950**	**368 198**
Impairment in the income statement (USD 1 000)				
Impairment/reversal of tangible fixed assets	-	-	-	-6
Impairment/reversal of intangible assets	-	365	-	992
Impairment of goodwill	-	-	-	29 161
Total impairment in the income statement	**-**	**365**	**-**	**30 147**

Note 6 Financial items

	Group			
	Q2		01.01.-30.06.	
(USD 1 000)	**2018**	**2017**	**2018**	**2017**
Interest income	**6 001**	**1 085**	**10 905**	**2 159**
Realized gains on derivatives	4 148	1 634	36 442	2 023
Change in fair value of derivatives	23 947	13 750	18 638	24 533
Net currency gains	22 682	-	1 890	3 674
Total other financial income	**50 777**	**15 384**	**56 970**	**30 230**
Interest expenses	48 956	44 874	93 507	86 040
Capitalized interest cost, development projects	-25 899	-24 135	-45 899	-42 436
Amortized loan costs	7 594	10 520	15 719	17 663
Total interest expenses	**30 651**	**31 259**	**63 326**	**61 267**
Net currency losses	-	2 426	-	-
Realised loss on derivatives	2 691	1 351	6 737	2 862
Change in fair value of derivatives	10 907	-	-	-
Accretion expenses	33 006	32 742	65 152	64 456
Other financial expenses	1 301	32 287	1 392	33 909
Total other financial expenses	**47 905**	**68 806**	**73 280**	**101 227**
Net financial items	**-21 778**	**-83 597**	**-68 732**	**-130 105**

Note 7 Tax

	Group			
	Q2		01.01.-30.06.	
Tax for the period appear as follows (USD 1 000)	**2018**	**2017**	**2018**	**2017**
Calculated current year tax	224 905	101 524	450 635	140 535
Change in deferred tax in the income statement	169 850	-35 290	229 547	84 903
Prior period adjustments	-536	710	-21 765	-540
Total tax (+)/tax income (-)	**394 219**	**66 944**	**658 417**	**224 898**

		Group	
Calculated tax receivable (+)/tax payable (-) (USD 1 000)	**30.06.2018**	**30.06.2017**	**31.12.2017**
Tax receivable/payable at 01.01.	1 234 850	307 977	307 977
Current year tax (-)/tax receivable (+)	-450 635	-140 535	-332 092
Taxes receivable/payable related to acquisitions/sales	-	-91	1 523 512
Net tax payment (+)/tax refund (-)	103 466	-	-303 589
Prior period adjustments	11 115	3 623	9 502
Currency movements of tax receivable/payable	9 792	5 925	29 540
Total net tax receivable (+)/tax payable (-)	**908 588**	**176 900**	**1 234 850**
Tax receivable included as current assets (+)	1 595 916	401 857	1 586 006
Tax payable included as current liabilities (-)	-687 328	-224 957	-351 156

Deferred tax (-)/deferred tax asset (+) (USD 1 000)	30.06.2018	Group 30.06.2017	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	-229 547	-84 903	-202 715
Deferred tax related to acquisitions/sales	-	3 616	-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 (+)	**-1 525 004**	**-1 124 750**	**-1 307 148**

	Group			
	Q2		01.01.-30.06.	
Reconciliation of tax expense (USD 1 000)	2018	2017	2018	2017
78% tax rate on profit before tax	413 572	98 935	745 416	275 818
Tax effect of uplift	-33 226	-31 757	-64 853	-62 246
Permanent difference on impairment	-	-	-	22 813
Foreign currency translation of NOK monetary items	-17 692	505	-1 474	-2 866
Foreign currency translation of USD monetary items	-103 404	34 661	7 168	46 662
Tax effect of financial and other 23%/24% items	56 454	-5 580	-5 016	-9 497
Currency movements of tax balances*	83 378	-37 733	-1 615	-49 910
Other permanent differences and prior period adjustment	-4 862	7 914	-21 209	4 125
Total taxes (+)/tax income (-)	**394 219**	**66 944**	**658 417**	**224 898**

* 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 tax rate as the company's functional currency is USD.

Note 8 Other short-term receivables

(USD 1 000)	30.06.2018	Group 30.06.2017	31.12.2017
Prepayments	77 311	40 166	59 100
VAT receivable	7 271	9 332	10 856
Underlift of petroleum	129 053	48 465	118 012
Accrued income from sale of petroleum products	198 688	75 086	105 670
Other receivables, mainly from licenses	116 837	273 445	241 879
Total other short-term receivables	**529 160**	**446 493**	**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)		Group	
	30.06.2018	**30.06.2017**	**31.12.2017**
Bank deposits	49 245	57 069	231 506
Restricted funds (tax withholdings)*	-	8 501	998
Cash and cash equivalents	**49 245**	**65 569**	**232 504**
Unused revolving credit facility	-	550 000	-
Unused reserve-based lending facility (see note 14)	3 550 000	2 055 000	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)		Group	
	30.06.2018	**30.06.2017**	**31.12.2017**
Fair value of contracts assumed in acquisitions*	127 539	180 771	149 031
Other long term liabilities	2 701	15 770	3 387
Total provisions for other liabilities	**130 240**	**196 541**	**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)		Group	
	30.06.2018	**30.06.2017**	**31.12.2017**
Unrealized gain currency contracts	-	7 398	12 564
Long-term derivatives included in assets	**-**	**7 398**	**12 564**
Unrealized gain on commodity derivatives	-	4 225	-
Unrealized gain currency contracts	29 377	1 924	2 585
Short-term derivatives included in assets	**29 377**	**6 149**	**2 585**
Total derivatives included in assets	**29 377**	**13 547**	**15 149**
Unrealized losses interest rate swaps	9 295	24 315	13 705
Long-term derivatives included in liabilities	**9 295**	**24 315**	**13 705**
Unrealized losses commodity derivatives	10 012	-	7 691
Short-term derivatives included in liabilities	**10 012**	**-**	**7 691**
Total derivatives included in liabilities	**19 306**	**24 315**	**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)	30.06.2018	Group 30.06.2017	31.12.2017
Current liabilities against JV partners	39 472	53 332	81 223
Share of other current liabilities in licences	320 862	388 982	409 387
Overlift of petroleum	25 373	23 516	9 610
Fair value of contracts assumed in acquisitions*	52 548	47 524	62 097
Other current liabilities**	140 495	106 436	141 880
Total other current liabilities	**578 749**	**619 789**	**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)	30.06.2018	Group 30.06.2017	31.12.2017
DETNOR02 Senior unsecured bond [1)]	233 713	223 523	230 375
AKERBP – Senior Notes (17/22) [3)]	392 535	-	391 664
AKERBP – Senior Notes (18/25) [4)]	492 779	-	-
Long-term bonds	**1 119 027**	**223 523**	**622 039**
DETNOR03 Subordinated PIK toggle bond [2)]	-	330 000	-
Short-term bonds	**-**	**330 000**	**-**
Total bonds	**1 119 027**	**553 523**	**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)] As described in the Q2 2017 report, the bond was repaid in July 2017.

[3)] 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.

[4)] 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)	30.06.2018	Group 30.06.2017	31.12.2017
Reserve-based lending facility	399 255	1 814 053	1 270 556
Long-term interest-bearing debt	**399 255**	**1 814 053**	**1 270 556**
Bridge facility	1 499 079	-	1 496 374
Short-term interest-bearing debt	**1 499 079**	**-**	**1 496 374**

The RBL facility was established in 2014 and is a senior secured seven-year facility. The facility was originally USD 3.0 billion, with an additional uncommitted accordion option of USD 1.0 billion. In connection with the acquisition of BP Norge AS, the facility size was increased to USD 4.0 billion. In addition a new, uncommitted, accordion option of USD 1.0 billion was added to the facility.

Current availability under the RBL is USD 4 billion. The financial covenants are as follows:

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

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.

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)	30.06.2018	Group 30.06.2017	31.12.2017
Provisions as of 1 January	3 043 884	2 156 921	2 156 921
Abondonment liability from acquisitions	-	-	1 315 181
Change in abandonment liability due to asset sales	-	-	-207 516
Incurred cost removal	-125 826	-19 811	-74 005
Accretion expense - present value calculation	65 152	64 456	129 619
Change in estimates and incurred liabilities on new drilling and installations	38 541	20 650	-276 315
Total provision for abandonment liabilities	**3 021 751**	**2 222 216**	**3 043 884**
Break down of the provision to short-term and long-term liabilities			
Short-term	168 956	112 907	268 262
Long-term	2 852 795	2 109 309	2 775 622
Total provision for abandonment liabilities	**3 021 751**	**2 222 216**	**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

The company has not identified any events with significant accounting impacts that have occured between the end of the reporting period and the date of this report.

Note 18 Investments in joint operations

Fields operated:	30.06.2018	31.03.2018
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:	30.06.2018	31.03.2018	Licence:	30.06.2018	31.03.2018
PL 001B	35.000%	35.000 %	PL 777	40.000%	40.000 %
PL 006B	90.000%	90.000 %	PL 777B	40.000%	40.000 %
PL 019	80.000%	80.000 %	PL 777C	40.000%	40.000 %
PL 019C	80.000%	80.000 %	PL 777D	40.000%	40.000 %
PL 019E	80.000%	80.000 %	PL 784	40.000%	40.000 %
PL 026B	90.260%	90.260 %	PL 790	30.000%	30.000 %
PL 027D	100.000%	100.000 %	PL 814	40.000%	40.000 %
PL 028B	35.000%	35.000 %	PL 818	40.000%	40.000 %
PL 033	90.000%	90.000 %	PL 818B	40.000%	40.000 %
PL 033B	90.000%	90.000 %	PL 822S	60.000%	60.000 %
PL 036C	65.000%	65.000 %	PL 839	23.835%	23.835 %
PL 036D	46.904%	46.904 %	PL 843	40.000%	40.000 %
PL 065	55.000%	55.000 %	PL 858	40.000%	40.000 %
PL 065B	55.000%	55.000 %	PL 861	50.000%	50.000 %
PL 088BS	65.000%	65.000 %	PL 867	40.000%	40.000 %
PL 150	65.000%	65.000 %	PL 868	60.000%	60.000 %
PL 169C	50.000%	50.000 %	PL 869*	60.000%	40.000 %
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 %	PL963**	70.000%	0.000 %
PL 626*	60.000%	50.000 %	PL964**	40.000%	0.000 %
PL 659	50.000%	50.000 %			
PL 677*	90.000%	60.000 %			
PL 748	50.000%	50.000 %			
PL 748B	50.000%	50.000 %			
PL 762	20.000%	20.000 %			
Number of licenses in which Aker BP is the operator				73	71

* Acquired through license transactions or licence splits.

** Interest awarded in the APA Licensing round (Application in Predefined Areas) in 2018. The awards were announced in 2018.

Fields non-operated:	30.06.2018	31.03.2018
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:	30.06.2018	31.03.2018
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*	23.835%	0.000 %
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%	0.000 %
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%	0.000 %
PL 962**	20.000%	0.000 %
PL 966**	30.000%	0.000 %
Number of licenses in which Aker BP is a partner	**58**	**53**

* Acquired through license transactions or licence splits.

** Interest awarded in the APA Licensing round (Application in Predefined Areas) in 2018. The awards were announced in 2018.

Note 19 Results from previous interim reports

(USD 1 000)	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3
Total income	**974 745**	**889 599**	**725 994**	**596 188**	**594 501**	**646 250**	**655 624**	**247 993**
Production costs	163 625	173 481	147 076	134 411	121 017	120 874	121 139	32 188
Exploration expenses	75 270	54 661	56 181	63 887	75 375	30 259	44 281	30 843
Depreciation	182 529	185 421	183 138	175 334	184 194	184 004	159 796	114 649
Impairments	-	-	21 111	1 091	365	29 782	44 627	8 429
Other operating expenses	1 324	3 640	13 549	2 893	3 113	8 051	5 029	6 223
Total operating expenses	**422 747**	**417 204**	**421 055**	**377 617**	**384 065**	**372 969**	**374 872**	**192 333**
Operating profit/loss	**551 998**	**472 395**	**304 940**	**218 571**	**210 436**	**273 280**	**280 752**	**55 660**
Net financial items	-21 778	-46 954	-56 526	-9 469	-83 597	-46 508	-70 572	-5 107
Profit/loss before taxes	**530 220**	**425 442**	**248 413**	**209 102**	**126 840**	**226 772**	**210 180**	**50 553**
Taxes (+)/tax income (-)	394 219	264 197	214 377	97 065	66 944	157 955	277 183	-12 880
Net profit/loss	**136 001**	**161 245**	**34 036**	**112 037**	**59 896**	**68 818**	**-67 003**	**63 433**

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

STATEMENT BY THE BOARD OF DIRECTORS AND CHIEF EXECUTIVE OFFICER

Pursuant to the Norwegian Securities Trading Act section § 5-5 with pertaining regulations, we hereby confirm that, to the best of our knowledge, the company's interim financial statements for the period 1 January to 30 June 2018 have been prepared in accordance with IFRS, as provided for by the EU, and in accordance with the requirements for additional information provided for by the Norwegian Accounting Act. The information presented in the financial statements gives a true and fair picture of the company's liabilities, financial position and results overall.

To the best of our knowledge, the Board of Directors' half-yearly report together with the yearly report, gives a true and fair picture of the development, performance and financial position of the company, and includes a description of the principal risk and uncertainty factors facing the company.

The Board of Directors and the CEO of Aker BP ASA
Akerkvartalet, 12 July 2018

Øyvind Eriksen, Chair of the Board

Kjell Inge Røkke, Board member

Anne Marie Cannon, Deputy Chair

Trond Brandsrud, Board member

Gro Kielland, Board member

Bernard Looney, Board member

Bjørn Thore Synsvoll Ribesen, Board member

Terje Solheim, Board member

Lone Margrethe Olstad, Board member

Kate Thomson, Board member

Karl Johnny Hersvik, Chief Executive Officer

Ørjan Holstad, Board member

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