Aker BP

ANNUAL REPORT 2018

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HIGHLIGHTS 2018 | Q1

Photo: Bo B. Randulff/Equinor

7 FEBRUARY - FURTHER INCREASE IN VALUE OF JOHAN SVERDRUP

The operator Statoil and the partnership announce a further increase in the value of the Johan Sverdrup field. Aker BP holds an 11.57 per cent working interest in the field. The increase is a result of continued high quality in project execution, good drilling efficiency and further maturation of the resource base.

26 MARCH - TWO PDOS APPROVED

The Ministry of Petroleum and Energy approves the plans for development and operation (PDOs) for the development projects Valhall Flank Vest and Skogul. Both are operated by Aker BP.

14 FEBRUARY

Dividends to shareholders: USD 112.5 million

16 JANUARY – OFFERED 23 NEW LICENCES IN APA AWARD

Aker BP is offered interests in 23 new production licences in Norway, of which 14 as operator, through the Awards in Pre-defined Areas licensing round. Of the 23 production licences, 15 are located in the North Sea, 3 in the Norwegian Sea and 5 in the Barents Sea.

19 FEBRUARY – PL340 EXPLORATION SUCCESS

Aker BP announces an oil discovery as the drilling of the Frosk exploration well 24/9-12 located near Alvheim in the North Sea is completed. Preliminary analysis indicates a discovery size of 30-60 million barrels of oil equivalents (mmboe), which is significantly more than the company's pre-drill estimates.

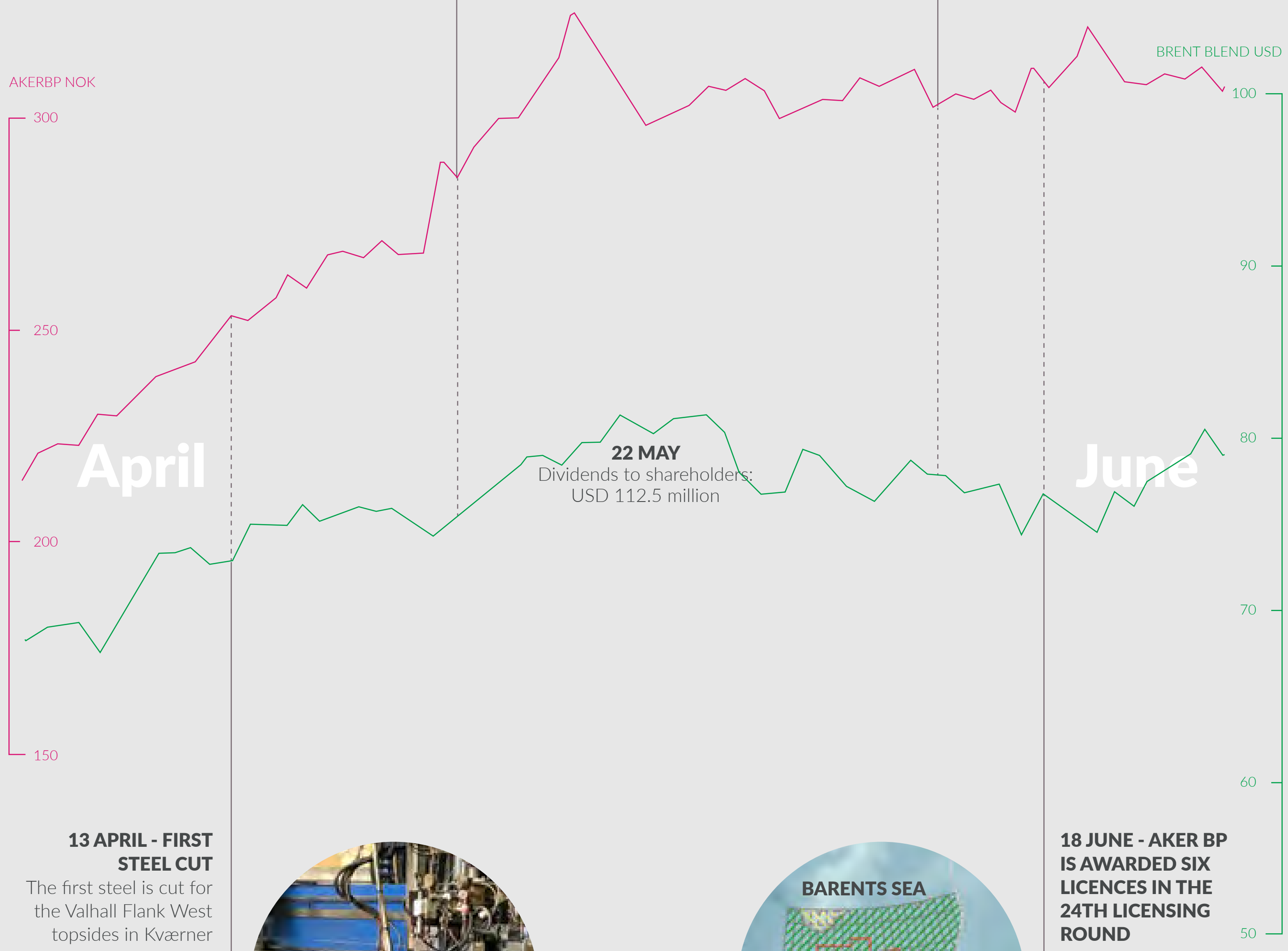
HIGHLIGHTS 2018 | Q2

8 MAY - AKER BP FORMS OPERATIONS ALLIANCE

The «Asset Integrity Alliance» consists of Aker BP, KAEFER, Prezioso Linjebygg and FORCE Technology. The four companies will work together to safeguard the technical integrity of Aker BP's installations. The Alliance will provide services within integrity management, platform services (ISO) and access technology.

6 JUNE - FIRST STEEL CUT ÆRFUGL

The partners in the Subsea-alliance marks the first cut of steel for the Ærfugl project at Aker Solutions in Sandnessjøen.



13 APRIL - FIRST STEEL CUT

The first steel is cut for the Valhall Flank West topsides in Kværner Verdal. The project reaches this milestone just four months after the Plan for Development and Operations was submitted the Norwegian Ministry of Petroleum and Energy.

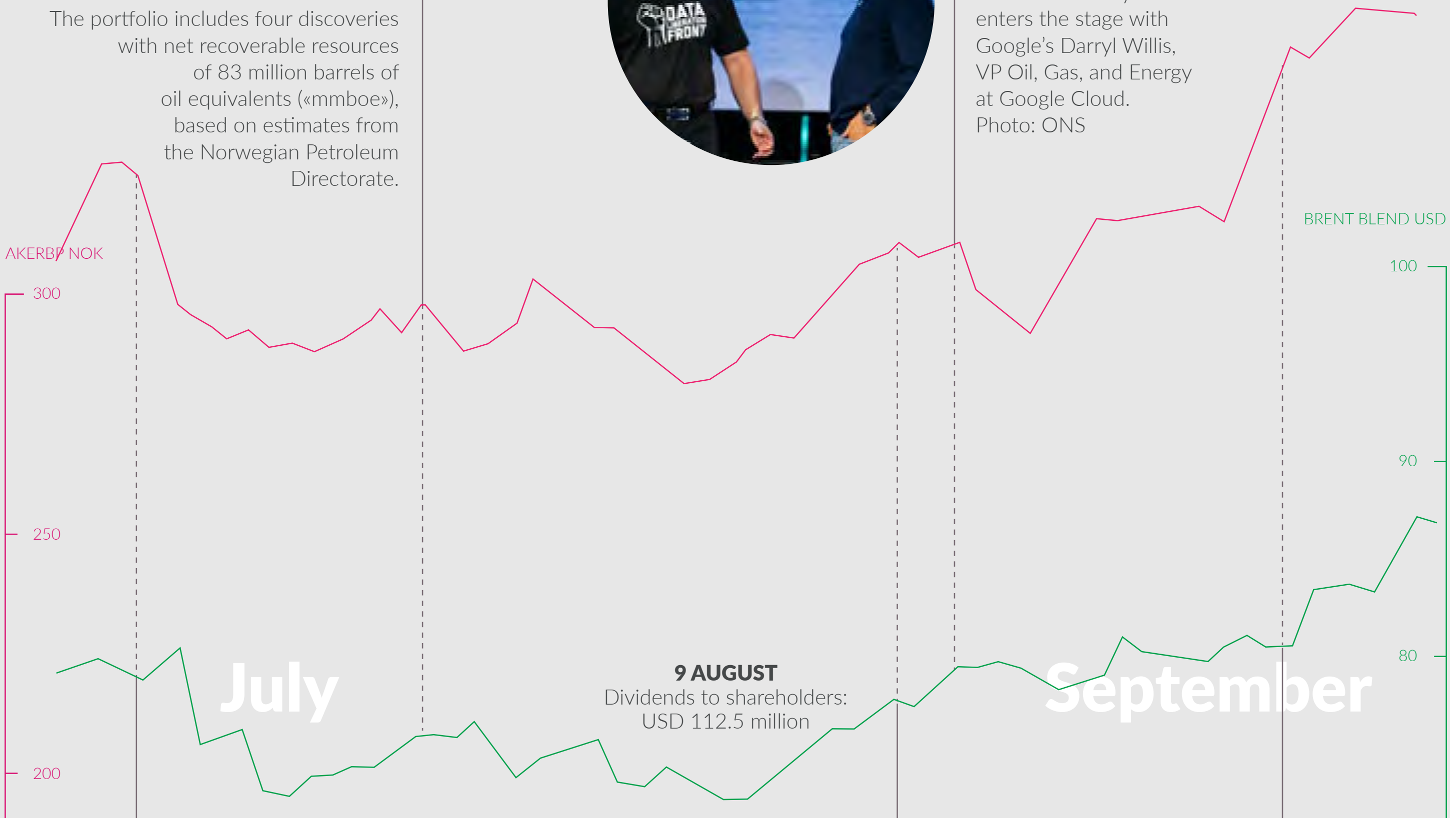
18 JUNE - AKER BP IS AWARDED SIX LICENCES IN THE 24TH LICENSING ROUND

Aker BP is offered interests in six new production licences in Norway, of which two as operator. All the new licences are located in the Barents Sea.

HIGHLIGHTS 2018 | Q3

31 JULY - AKER BP ACQUIRES LICENCE PORTFOLIO FROM TOTAL
Aker BP enters 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 of oil equivalents («mmboe»), based on estimates from the Norwegian Petroleum Directorate.

31 AUGUST - AKER BP AND GOOGLE AT ONS
Aker BP and Google demonstrate how digital solutions have started to reconstruct the oil industry at the ONS conference.
CEO Karl Johnny Hersvik enters the stage with Google's Darryl Willis, VP Oil, Gas, and Energy at Google Cloud.
Photo: ONS



9 AUGUST
Dividends to shareholders:
USD 112.5 million

27 AUGUST - MORE RESOURCES AND LOWER COSTS AT JOHAN SVERDRUP
The Johan Sverdrup partnership submits the plan for development and operations (PDO) for the second phase of the Johan Sverdrup field development to the Norwegian Ministry of Petroleum and Energy. The Phase 2 PDO demonstrates further improvements in resources and investment cost.

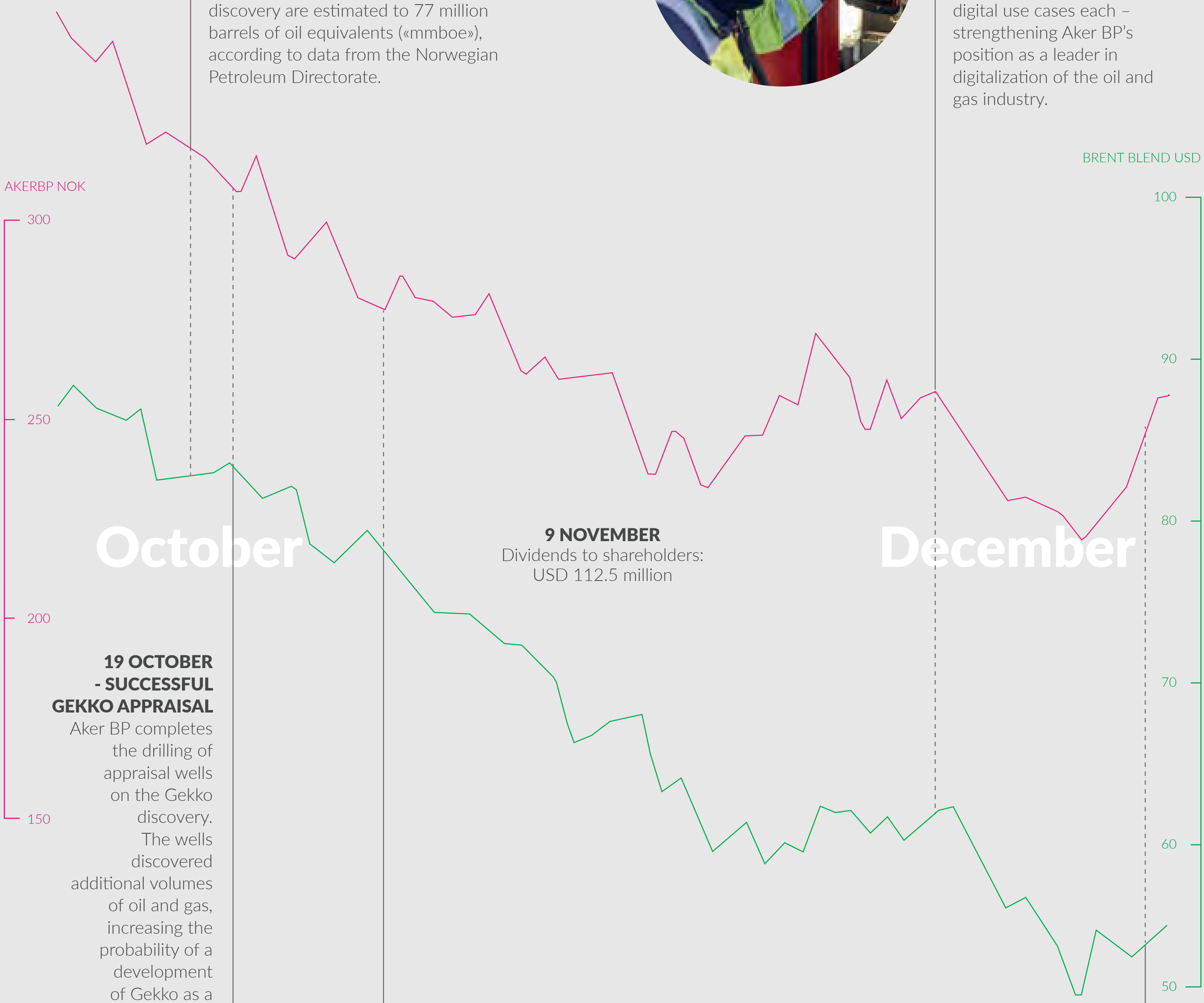
10 JULY - ALLIANCE AGREEMENT SIGNED FOR MODIFICATIONS
Aker BP and Aker Solutions are forming an alliance to deliver modification projects on three of Aker BP's fields. The alliance agreement comprises all modification work on the offshore installations on Valhall, Ula and Skarv. Aker Solutions' fabrication workshops in Egersund and Sandnessjøen will also deliver work through the Modification Alliance.

21 SEPTEMBER – HANZ IN LINE WITH EXPECTATIONS
Aker BP concludes the drilling of appraisal wells on the Hanz field near Ivar Aasen.

HIGHLIGHTS 2018 | Q4

15 OCTOBER - AKER BP ACQUIRES KING LEAR DISCOVERY
Aker BP enters 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. Net recoverable resources in the King Lear discovery are estimated to 77 million barrels of oil equivalents («mmboe»), according to data from the Norwegian Petroleum Directorate.

12 DECEMBER – DIGITALIZATION PROJECT DELIVERS
The digital project in Aker BP - Eureka - delivers the first super sprint. Five crews have worked through the autumn and deliver multiple digital use cases each – strengthening Aker BP's position as a leader in digitalization of the oil and gas industry.



9 NOVEMBER
Dividends to shareholders:
USD 112.5 million

19 OCTOBER - SUCCESSFUL GEKKO APPRAISAL
Aker BP completes the drilling of appraisal wells on the Gekko discovery. The wells discovered additional volumes of oil and gas, increasing the probability of a development of Gekko as a tie-back to the Alvheim FPSO.

30 OCTOBER - SAFE AND EFFECTIVE PLUGGING OF WELLS AT VALHALL
Maersk Invincible completes the plug and abandonment (P&A) programme of wells at the Valhall field centre. The work is done faster than planned, with no harm to people, equipment or the environment – and zero CO_2 and NOx emissions.

31 DECEMBER - RECORD HIGH INCOME
Aker BP's total income amounted to USD 3,750 million for the year. This is an increase of 46 per cent compared to 2017.

LETTER FROM THE CEO

Once again, Aker BP demonstrates significant value creation. 2018 was a year of robust development and growth for our company. As a result, we delivered on our goals and distributed USD 450 million in dividends to our shareholders.

2018 FIELD PRODUCTION

320,000
boepd (operated production)

155,700
boepd (net production)

$12
production cost per barrel

2018 HIGHLIGHTS

Operational performance in 2018 was strong. We delivered record-high production. Our net production for the full year was 155.7 thousand boepd (barrels of oil equivalents per day) — up more than 12 % compared to 2017.

Production costs for 2018 amounted to USD 12 per boe (barrel of oil equivalent). Total production volume was 56.8 million boe. The two main contributors to performance improvement were greater efficiency and new wells. Production efficiency was high across our assets — and we succeeded in delivering stable production despite ongoing modification work at all our producing assets.

Aker BP significantly increased reserves and resources in 2018. Our 2P reserves rose to 917 mmboe (million barrels of oil equivalents) from 914 mmboe; thus, we replaced more barrels than we produced during the year. Moreover, our 2C contingent resources grew by 23 % to 946 mmboe due to exploration success and business development.

We made two significant acquisitions in 2018: a licence portfolio from Total E&P Norge containing four discoveries, and the King Lear discovery from Equinor. Together, they added 173 mmboe to our contingent resources and strengthened our position in core areas.

We also ramped up our exploration activities in 2018. This resulted in the very encouraging Frosk discovery as well as a positive appraisal of the Gekko discovery and added approximately 55 mmboe in net volumes. Building on determined efforts over several years, Aker BP is now the second largest licence holder on the Norwegian Continental Shelf.

That said, our goal is not to maximize the number of barrels produced, but rather to maximize value creation. We want to build a portfolio that is robust across industry cycles and delivers industry-leading returns. To ensure high and sustainable returns on investments, we rank our projects according to break-even oil price – and we only invest in projects that are profitable at USD 35 per barrel or less. Some 90 % of our contingent resources already meet this requirement.

Aker BP demonstrated strong capital discipline in 2018. Capital spending was USD 1.20 billion; a figure somewhat below the communicated guidance level. The three main ongoing field development projects — Ærfugl, Skogul and Valhall Flank West — are all on track. We delivered industry-leading drilling performance in 2018; development drilling averaged 200 metres per day, and exploration drilling averaged 170 metres per day including data acquisition. Well abandonment expenditures were lower than projected, due to strong performance by the Maersk Invincible rig.

The operational activities carried out in 2018, outlined above, generated considerable value for our shareholders. We paid out USD 450 million in dividends in 2018; up USD 200 million from the previous year.

RECONSTRUCTING OUR BUSINESS

In 2018, Aker BP truly took the lead in digitalizing the oil and gas industry. Key success factors for digitalization are: data liberation and data sharing; implementing technology that can utilize diverse data sources; securing an effective, user-friendly environment and running agile work processes. Vital, too, is creating a dynamic organization of users, equipment suppliers, and software and IT providers.

Everybody in our industry seems to be talking about digitalization. To me, putting words into action is what counts. As an example: Aker BP kicked off 2019 with relocating the primary Ivar Aasen control room onshore. To my knowledge, Aker BP is the first operator to have a manned platform controlled from shore, which in this case is technology-savvy Trondheim city centre. I am extremely proud of the Aker BP team that carefully planned and executed the project throughout 2018.

In 2017, Aker BP in collaboration with Aker ASA and IT innovator John Markus Lervik established the Cognite firm to develop a unique industrial-data platform. The objective has been to make all Aker BP data available to approved users inside and outside the company, on any device, at any time, with extremely low latency. In 2018, we achieved all this — and created a unique competitive edge for Aker BP.

Data, both live and archived, are continuously and securely accessible, infinitely scalable and contextualized. The Cognite Data Platform enables performance improvements across-the-board via user-friendly applications that feature machine learning and advanced analytics.

> “In 2018, Aker BP truly took the lead in digitalizing the oil and gas industry.

Ivar Aasen onshore control room.

The Eureka Digital Lab, Aker BP's centre of excellence for digital projects, was launched in 2018. Within a few months, the team developed several important applications, including our digital worker initiative. This high-profile project will be fully implemented on all Aker BP assets in 2019.

Another pillar of our improvement strategy is reorganization of the value chain through strategic partnerships and alliances. Following a limited start-up of our subsea alliance in 2016, seven alliances were on board by year-end 2018. The majority of our CAPEX is invested through these alliances. And the results are tangible. The alliance model is creating value through greater productivity and efficiency. Nevertheless, there remains considerable room for improvement across all alliances, and it is inspiring to see the motivation to excel within each alliance.

In terms of concrete results, the subsea alliance continues to deliver tie-in projects safely, speedily and at lower cost, compared to traditional tie-in projects.

At the Valhall Flank West project, we are also benefiting from the alliance model. Aker BP has benchmarked this development project with comparable projects on the Norwegian Continental Shelf. Here, we are experiencing lower facility costs and shorter engineering and project durations.

In 2018, we integrated and embedded responsible climate-related performance into Aker BP's strategy and decision making. The company's climate road map reflects our strategic priorities to cut down on emissions and boost energy efficiency across operations. The company's CO_2 emission intensity target is set at less than 8 kg of CO_2 per produced boe (operated fields only). In 2018, our actual carbon intensity was 7 kg CO_2 per boe. This figure is below the targeted ceiling, mainly due to improved energy efficiency and electrification of a jack-up rig at Valhall.

READY FOR FURTHER GROWTH

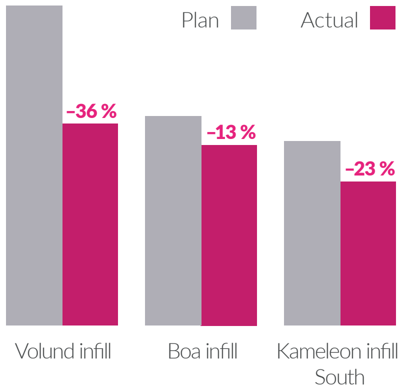
Aker BP's 2019 exploration campaign got off to an excellent start with an oil and gas discovery at the Froskelår prospect in the North Sea. The discovery was within the projected pre-drill range of 45–153 mmboe. In 2019, we will continue to pursue organic growth through a total of 15 exploration wells, targeting net prospective resources of 500 mmboe. The Valhall Flank West and Johan Sverdrup projects will come on stream in 2019.

2018 was a fantastic year. We can be very pleased with the year's financial results, which show a net profit of USD 476 million — an increase of 73 %. Through excellent project execution, a strong cash flow from our existing portfolio and a solid balance sheet, we have built a foundation for Aker BP's further growth. This strength allows us to increase our dividend payment objectives. The Board of Directors has proposed a 2019 dividend distribution totalling USD 750 million, up from USD 450 million in 2018, and indicated its ambition to raise dividend payouts through to 2023 by USD 100 million per year.

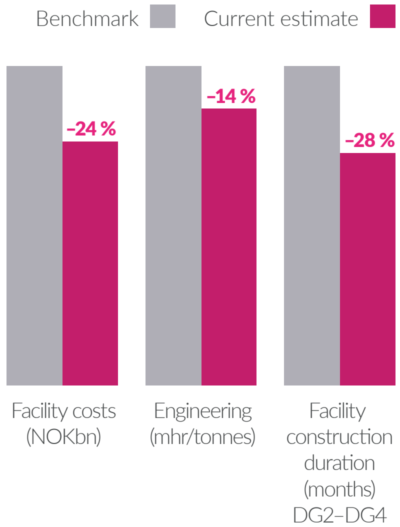
Safe and reliable operations are the foundation on which we stand. At the heart of our activities and success is the dedicated Aker BP team. It is a powerful team ready to drive improvements, increase efficiency and boost productivity — a team I am honoured and proud to lead!

Karl Johnny Hersvik
CEO, Aker BP ASA

SUBSEA ALLIANCE COST IMPROVEMENTS

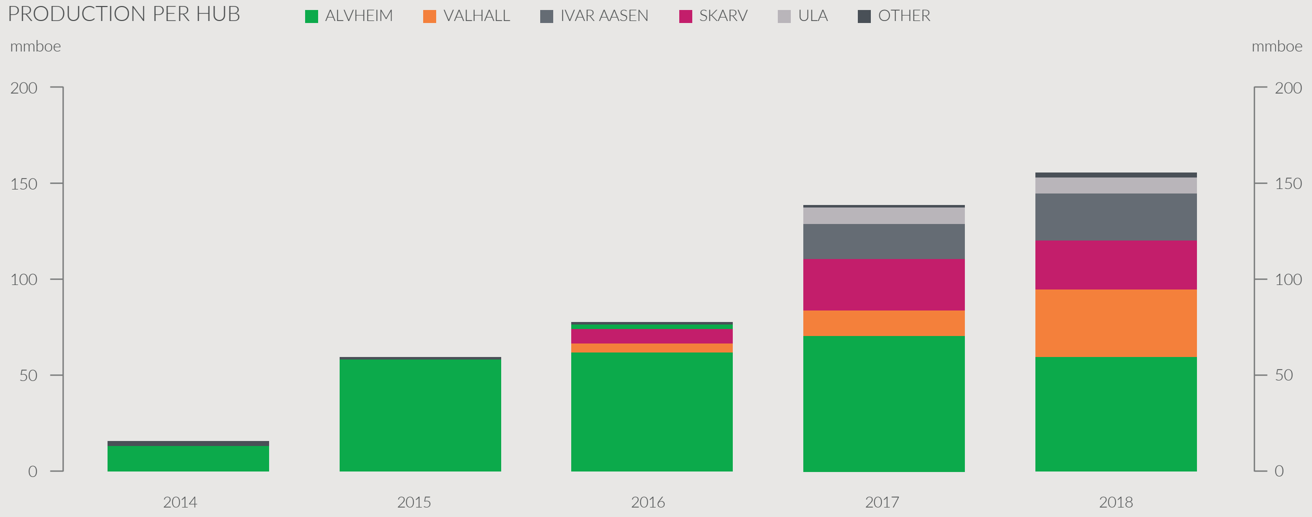


VALHALL FLANK WEST ALLIANCE EFFECTS

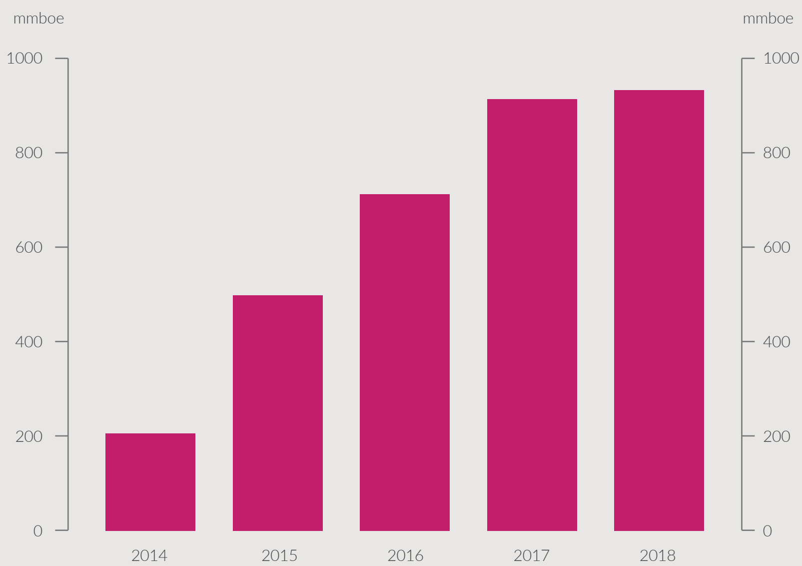


KEY FIGURES 2018

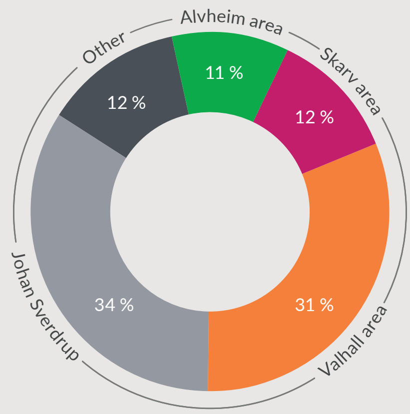
PRODUCTION PER HUB



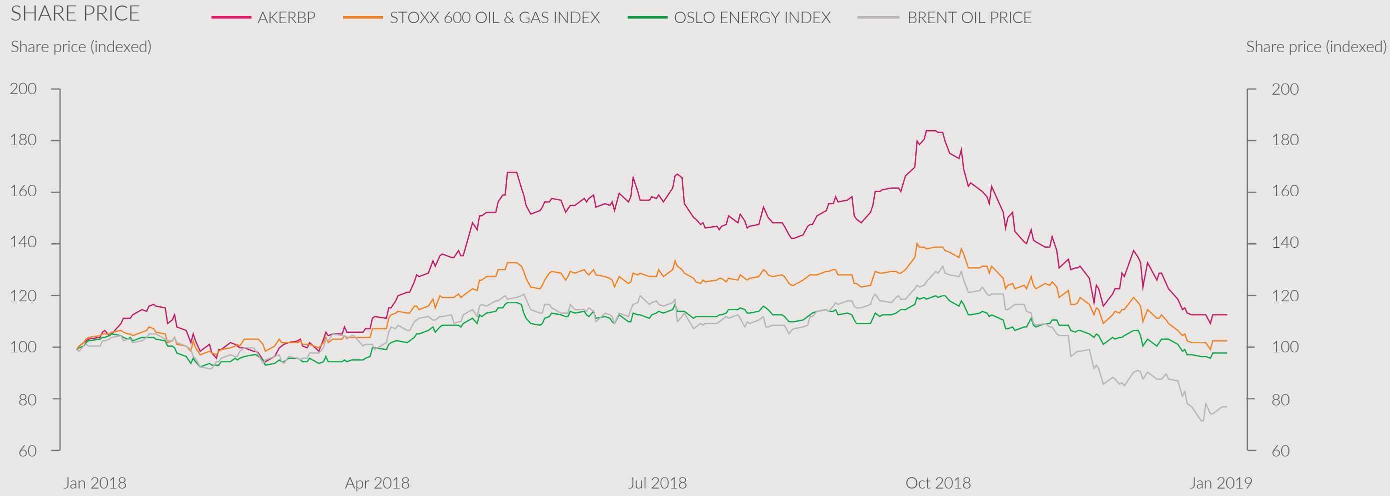
P50 RESERVES DEVELOPMENT



P50 RESERVES 2018



SHARE PRICE



KEY FIGURES 2018

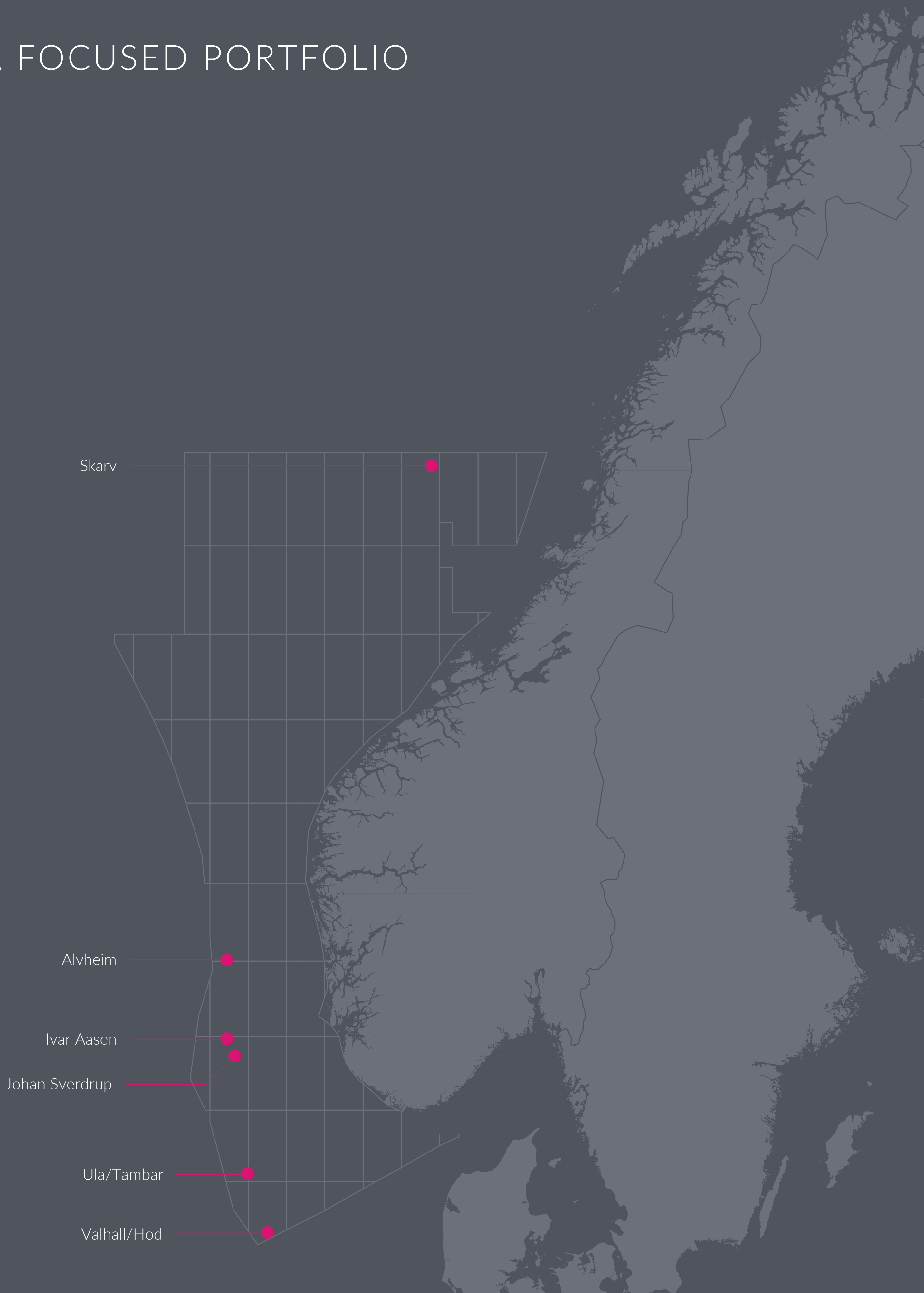
SUMMARY OF FINANCIAL RESULTS

Key figures	Unit	Q1-18	Q2-18	Q3-18	Q4-18	2018	2017
Total income	USDm	890	975	1 000	886	3 750	2 563
Operating profit	USDm	472	552	548	403	1 975	1 007
Net result	USDm	161	136	125	54	476	275
Earnings per share	USD	0,45	0,38	0,35	0,15	1,32	0,81
Production cost per barrel	USD/boe	12	11	12	13	12	10
Depreciation per barrel	USD/boe	13	13	14	14	13	14
Cash flow from operations	USDm	600	613	697	1 889	3 800	2 155
Cash flow from investments	USDm	- 378	- 403	- 457	- 910	- 2 147	- 3 059
Total assets	USDm	11 985	12 147	12 364	10 777	10 777	12 019
Net interest-bearing debt	USDm	3 048	2 968	2 849	1 973	1 973	3 156
Cash and cash equivalents	USDm	38	49	127	45	45	233

SUMMARY OF OPERATIONAL PERFORMANCE

Key figures	Unit	Q1-18	Q2-18	Q3-18	Q4-18	2018	2017
Alvheim (65 %)	boepd	40 516	40 091	38 872	43 406	40 724	53 849
Bøyla (65 %)	boepd	3 235	3 265	3 125	2 039	2 913	4 357
Gina Krog (3.3 %)	boepd	1 505	1 848	1 317	2 318	1 748	798
Hod (90 %)	boepd	1 016	1 063	872	802	937	530
Ivar Aasen (34.8 %)	boepd	24 421	23 699	22 651	23 343	23 523	18 100
Skarv (23.8 %)	boepd	27 092	27 579	23 313	23 454	25 344	26 680
Tambar/Tambar East (55 %/46.2 %)	boepd	1 611	5 398	4 008	2 572	3 402	1 941
Ula (80 %)	boepd	6 486	5 361	6 498	5 784	6 032	6 466
Valhall (90 %)	boepd	33 500	32 670	35 120	38 816	35 041	13 357
Vilje (46.9 %)	boepd	5 090	4 098	3 716	3 257	4 034	5 304
Volund (65 %)	boepd	14 109	12 649	11 016	9 655	11 842	7 342
Other (Atla, Enoch)	boepd	71	67	57	275	118	103
TOTAL	boepd	158 649	157 784	150 564	155 720	155 658	138 825
Oil price	USD/bbl	69	76	78	64	72	56
Gas price	USD/scm	0,28	0,28	0,30	0,30	0,29	0,21

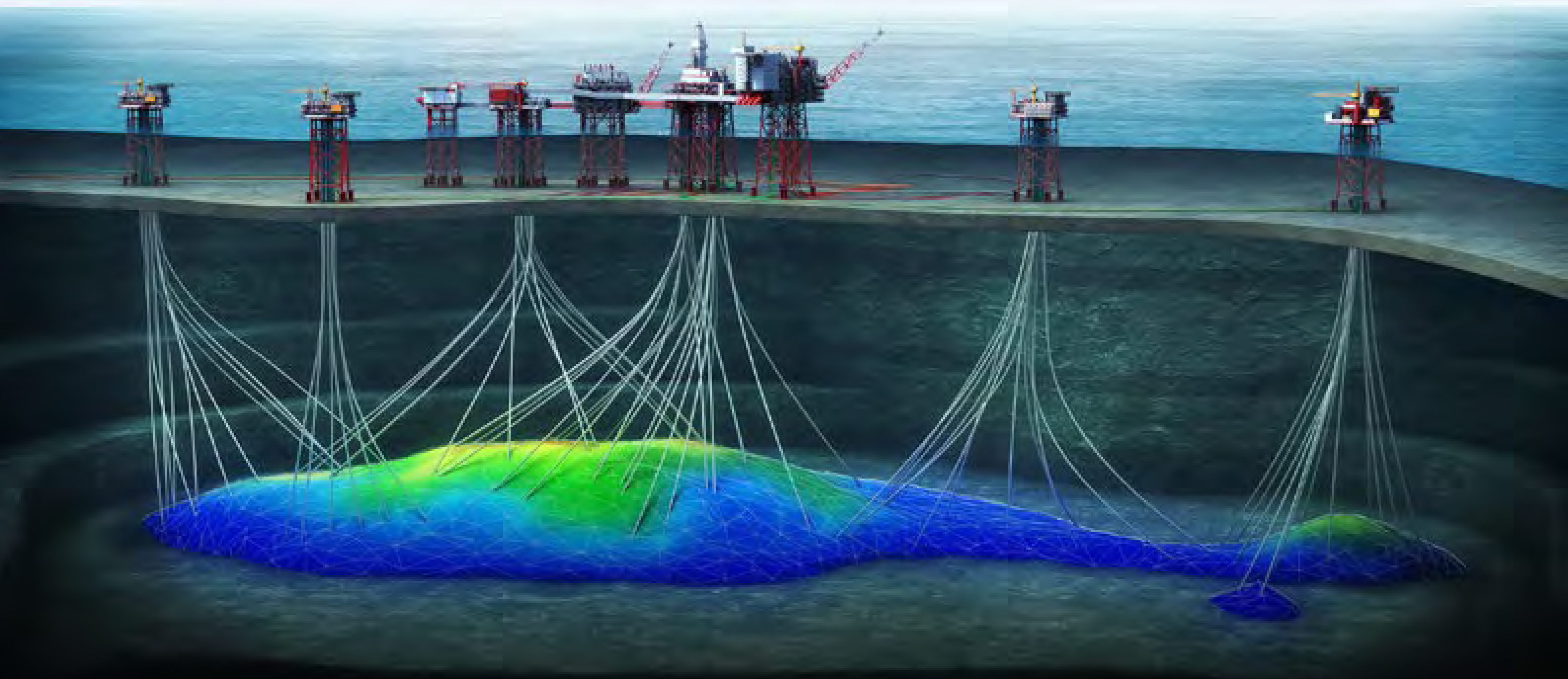
A FOCUSED PORTFOLIO



THE

VALHALL AREA

Simultaneous drilling operations, plugging and abandonment of old wells, multiple new wells and a major development project on track. The high activity level at Valhall demonstrates Aker BP's determination to reach the ambition of another billion barrels produced from the area.



PRODUCTION 2018

35.9 MBOEPD (net)

PRODUCTION EFFICIENCY

87 %

PRODUCTION START: VALHALL 1982, HOD 1990

In the beginning of 2019, Aker BP had three drilling operations ongoing at the same time in the Valhall and Hod area. In addition, the rig Maersk Reacher was connected to the field centre, serving as a flotel.

NEW WELLS ON STREAM

Valhall can look back at a fantastic year. Production efficiency gradually improved, and the production volumes increased through the year. During 2018, two new wells were drilled from Valhall IP. Better technology such as geo-steering enables longer wells and contributes to good economics and better recovery. The wells are part of a drilling programme launched in 2017 comprising seven wells. Another three wells are still to be completed.

Maersk Invincible successfully drilled a new water injector on Valhall Flank North in November with a 1650m long reservoir section. This is 500 metres longer than planned, and the well increased the resources with 2 mmboe. The water injector was drilled with glass beads in the mud to achieve an extremely light mud-weight – a technological breakthrough for Valhall. Two Flank North wells which had been closed for over a year for pressure build-up in the north basin, were put back on stream following the successful drilling of the water injection well.

Once the water injection well was completed, Maersk Invincible drilled a production well, this one also with a longer reservoir section than planned. This increases the recovery potential from the well significantly.

VALHALL FLANK WEST PROGRESSING

The Ministry of Petroleum and Energy approved the plan for development and operation for the Valhall Flank West development in March. The first steel for the new topsides and jacket was cut shortly after at Kværner's yard in Verdal.

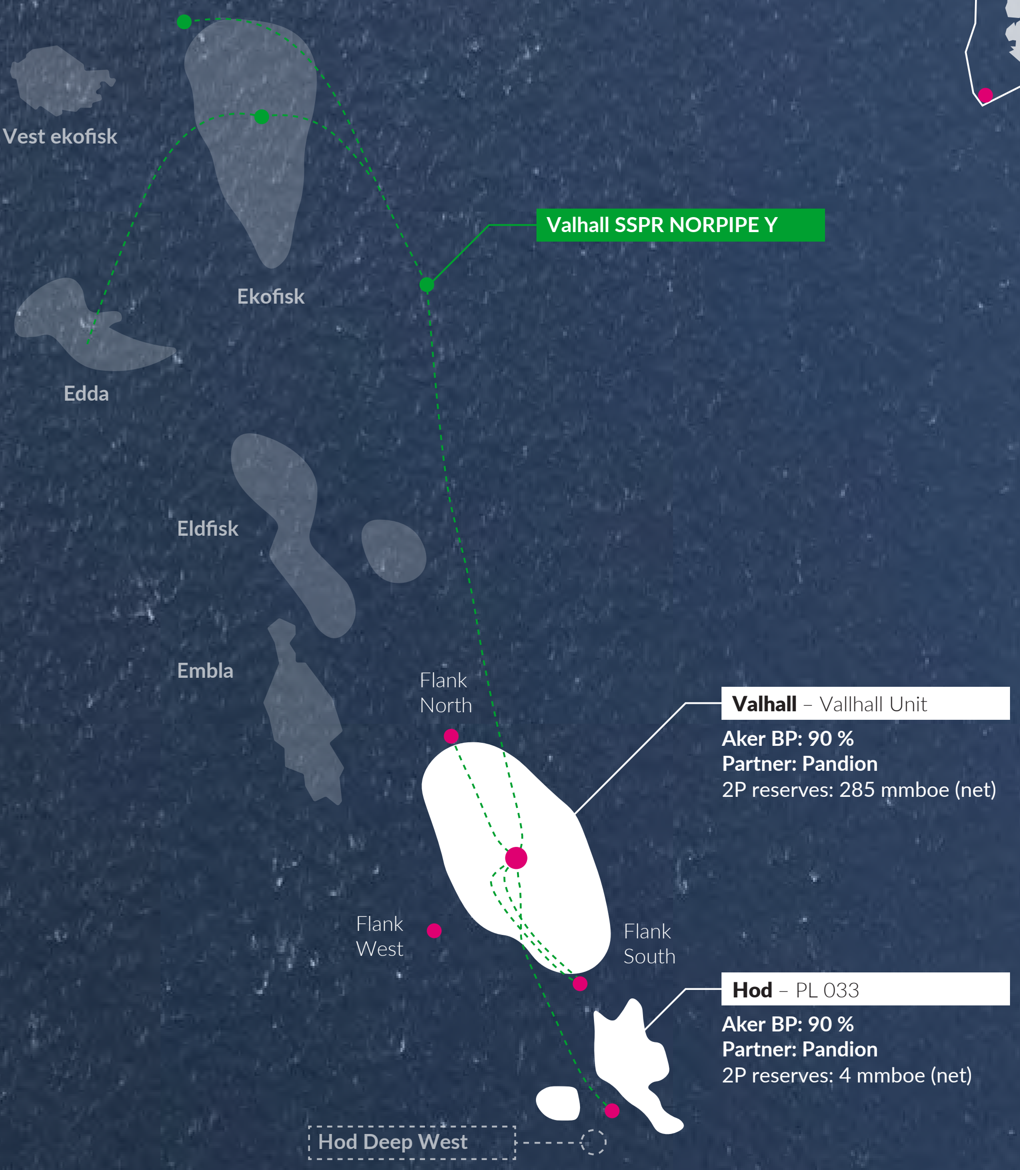
The West Flank is developed with an unmanned wellhead platform tied back to the field centre. Six wells will be drilled in the summer of 2019. NOK 5.5 billion is invested in the project, which has a break-even price of USD 28.5 per barrel.

As the year ended, both the topsides and the jacket were rising at the yard. Modification work was taking place on the Valhall field centre. One million man-hours had been worked without serious HSE incidents. The project is progressing as planned, targeting sail-away and installation of the jacket in the spring and the topsides in the summer. First oil is expected in the fourth quarter.

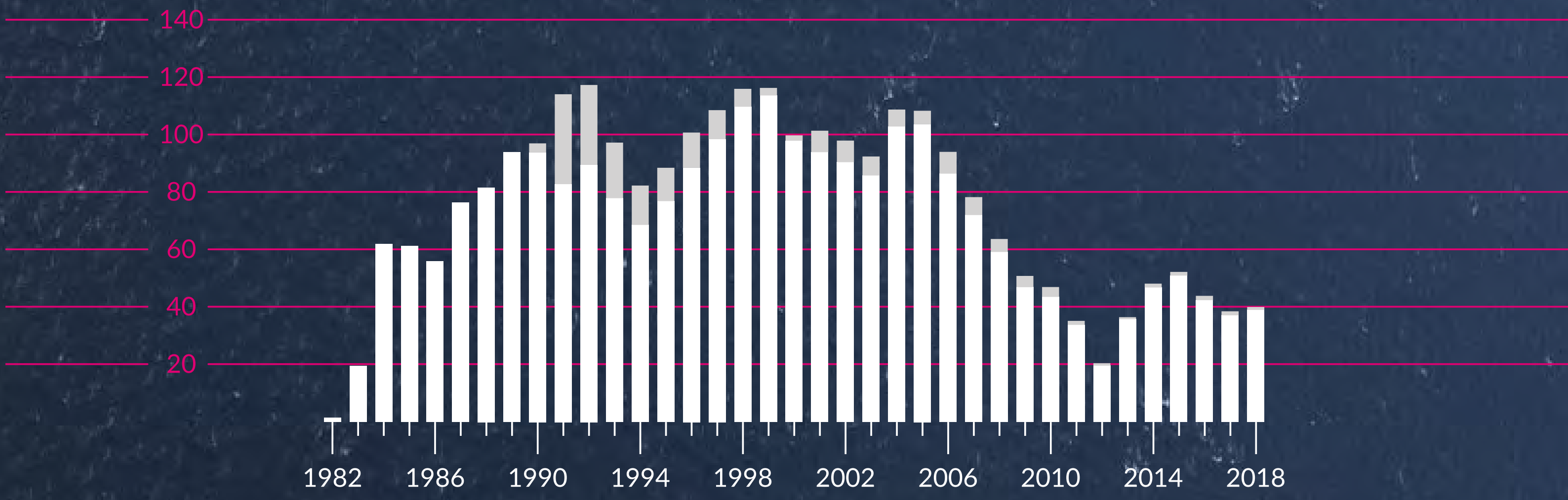
Valhall Area

Producing field · Field development · Discovery · Exploration prospect

Net 2P Reserves: 288 mmboe



Production history (mboepd gross) Valhall Hod



SUCCESSFUL PLUGGING OPERATIONS

Maersk Invincible left the Valhall field centre after successfully completing the plug and abandonment programme in the autumn. Since 2017, the rig plugged a total of 14 wells through the Valhall DP platform. The work was done faster than planned, with no harm to people, equipment or the environment – and zero CO_2 and NOx emissions.

Continuous improvements reduced the average time per well by 50 %, despite a rise in the complexity of the wells towards the end of the campaign. Maersk Invincible was supplied with electricity through the Valhall field. This was a pioneer project for Aker BP, underpinning the company's strategy of developing solutions that contribute to minimizing the environmental impact of our activities.

TESTING NEW TECHNOLOGY

Towards the end of the year, the first liner with Fishbones Stimulation Technology was installed on Valhall IP, in a well targeting the Tor formation. This represents the first installation of Fishbones in a carbonate formation in the North Sea, and the world's first with particle control. It has the potential to reduce stimulation time, cost, stimulation pressure, provide controlled stimulation and reduce risk of chalk influx compared to the current practice of proppant fracturing. The effects of Fishbones are expected in first quarter of 2019.

Another simulation technology called «Single trip multifrac» has been tested and is under qualification at Valhall. A project which aims to fully automate the drill deck on Valhall IP is maturing, and expected start-up is in the autumn of this year. Finally, full Wi-Fi coverage will be installed at the Valhall field centre, and handheld devices will be rolled out to all operators during the year.

FUTURE OUTLOOK

Aker BP believes that there is still a huge resource potential to be unlocked in Valhall and continues to actively target upside potential in the area. At the start of 2019, the Maersk Interceptor rig was drilling the Hod appraisal well. The rig will also carry out core testing and data collection in the diatomite, which is a tight chalk reservoir with a large resource base. Following the appraisal well, Aker BP will drill the exploration well Hod Deep West in 2019.

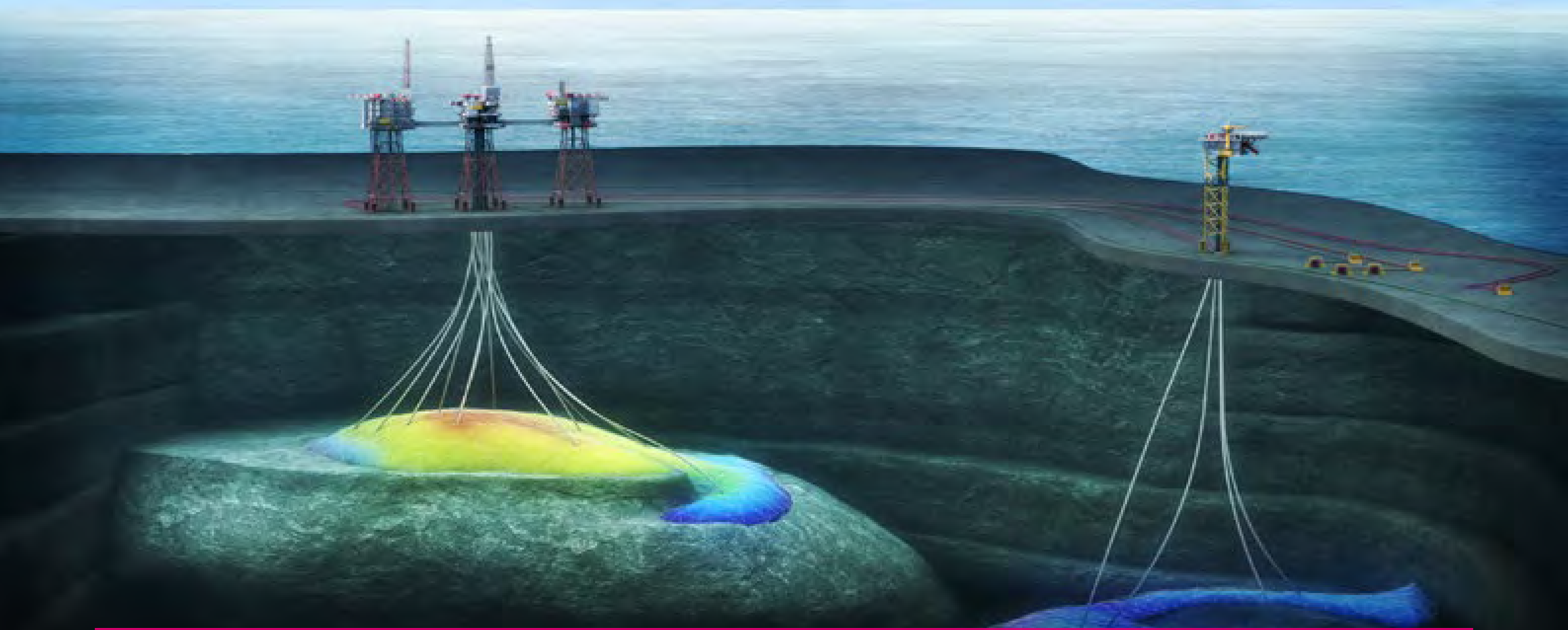
At the same time the Hod re-development project continues to mature towards a concept selection.

A programme for further infill drilling, targeting the Lower Hod formation through the IP drilling rig, will also be sanctioned.

Preparations for the removal of the QP platform is ongoing. In the summer, the Allseas vessel Pioneering Spirit will remove the old topsides in one lift.

THE
ULA AREA

In 2018, significant steps were taken towards realising the ambition of extending Ula's lifetime by more than 20 years. As the year concluded, the activity in the asset reached levels that have not been seen for a decade – demonstrating Aker BP's intent to rejuvenate Ula as an area hub.



PRODUCTION 2018

9.4 MBOEPD (net)

PRODUCTION EFFICIENCY

67 %

PRODUCTION START: ULA 1986, TAMBAR 2001, TAMBAR EAST 2007, ODA EXPECTED IN 2019

The Safe Scandinavia flotel arrived in the Ula field in August 2018. The flotel is set to be moored at the field until the spring of this year, enabling more than 100 extra people to work on the ongoing projects. The projects aim to improve facility technical integrity, reduce maintenance backlog, address obsolescence and allow for start-up of both the third-party Oda field and Ula drilling operations.

ODA ON TRACK FOR FIRST OIL

The Spirit Energy operated Oda field is on track to start production during the first quarter of 2019. Aker BP holds a 15 % working interest in the Oda field.

Oda is a subsea field which is tied back to Ula re-using existing Oselvar inlet facilities on Ula. The field is developed with two production wells and one water injector. Aker BP has carried out modification work on Ula. The work scope includes modification of the Oselvar facilities and installation of fiscal metering, water treatment and water injection.

The Oda tie-in will give Aker BP third party income. In addition, gas from Oda will be used to increase oil recovery from the Ula reservoir. The gas will be used in Ula's enhanced oil recovery WAG scheme (water alternating gas) in which water and gas are alternately injected in the reservoir to increase oil recovery. The Ula reservoir has responded extremely well to WAG, and Aker BP believes further potential can be exploited.

TAMBAR WELLS ON STREAM

Two new wells on Tambar were put on stream during the first half of 2018. Approximately NOK 1.5 billion was invested in the Tambar re-development project, which extends the economic lifetime of the field.

Aker BP is now looking at the potential to optimize the production from the new wells. One important step in the optimization is the start-up of gas lift, which is expected during the spring of this year.

INCREASING RELIABILITY

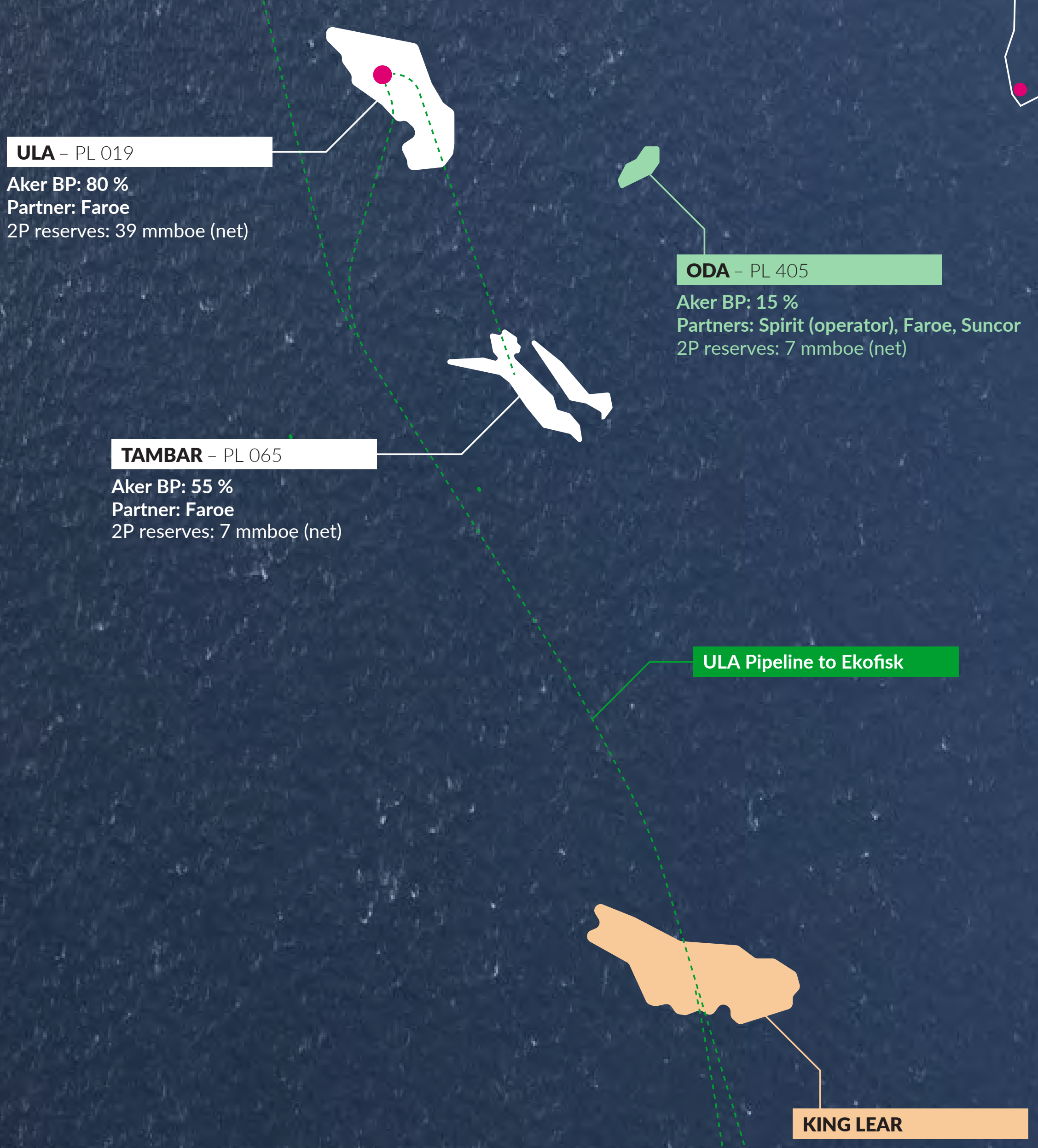
The upgrade of the Ula power system is a major project which moved into the offshore execution phase in 2018. Three gas-turbine-driven electrical power generation units will be replaced. The first unit will be operational in the spring of 2019. The next two units will be upgraded during 2019 and 2020.

The fire and gas detection systems are currently being upgraded, and the work will be completed during the year. Other work is being performed to reduce the maintenance and fabric maintenance backlog which will in turn improve the reliability and technical integrity of the facility.

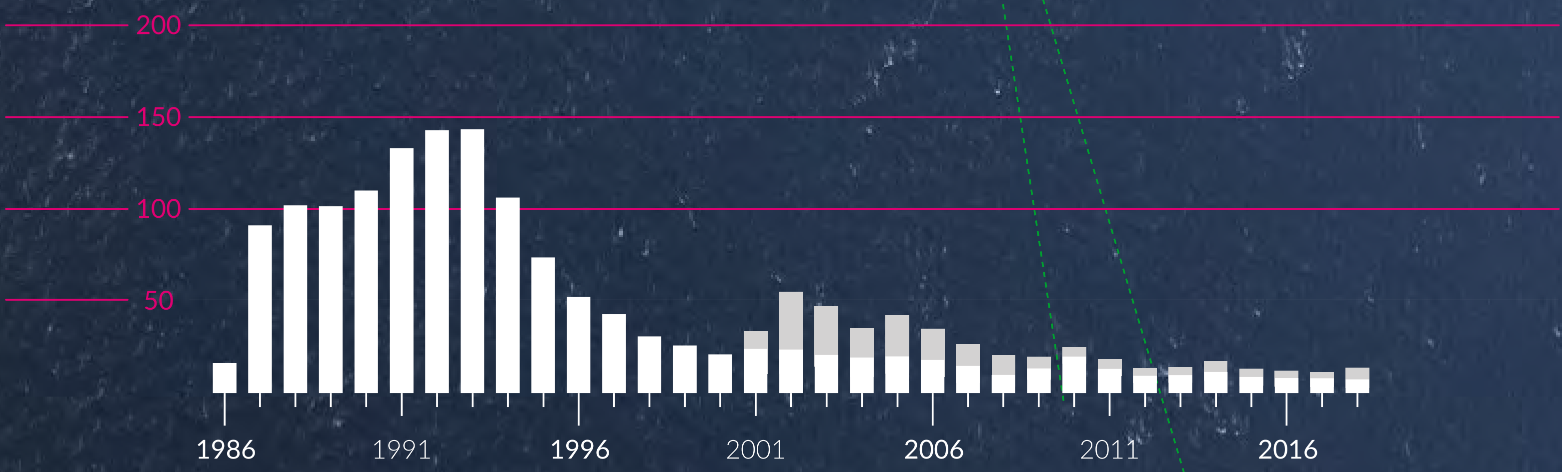
Ula Area

Producing field | Field development | Discovery | Exploration prospect

Net 2P Reserves: 53 mmboe



Production history (mboepd gross) Ula Tambar



EXPLORING NEW OPPORTUNITIES

An Ula drilling programme was sanctioned by the Aker BP board in the summer of 2018. The Maersk Integrator heavy duty jack-up drilling unit is expected to arrive at the field early in the summer of 2019. It will perform drilling and workover activity on six production and injection wells.

In preparation for the rig arrival, the old drilling tower on Ula D is being removed and the platform modified to otherwise accommodate the rig. In April 2019 the Saipem 7000 heavy lift vessel will remove the old derrick. Drilling operations will be conducted from the mobile rig, through the Ula D platform.

NEW POTENTIAL THROUGH OLD KING

In October 2018 Aker BP acquired 77.8 % interest in the King Lear discovery from Equinor. The terms of the agreement were fulfilled on 27 December and Aker BP became Operator of the licence.

King Lear is located approximately 50 kilometres south of the Ula field. It is a high pressure, high temperature gas condensate discovery which is a potential tie-back to Ula. A tie-back would improve capacity utilization of the Ula facilities and provide significant additional volumes of injection gas to allow expansion of the Ula WAG scheme. Surplus gas will be exported, and Ula would again become a net gas export facility.

FUTURE OUTLOOK

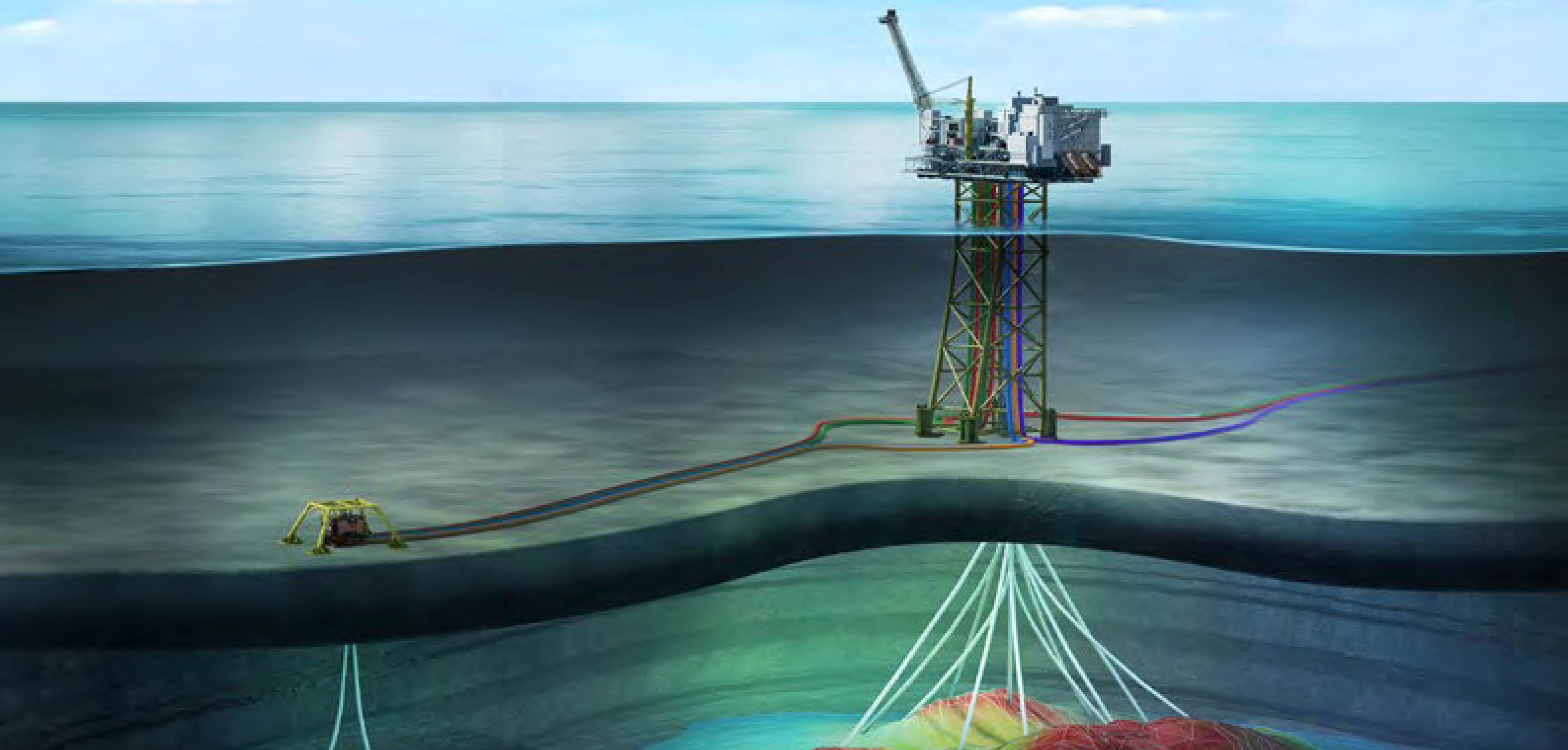
Aker BP continues to mature opportunities in the greater Ula area, including further development of the Ula Jurassic and Triassic reservoirs as well as Tambar. New technology might allow for an increased upside potential.

Several exploration targets have been identified in the area, and Kark will be drilled in 2019. The company is also focusing on further area prospectivity in the Upper Jurassic.

There are several third-party discoveries in the area which are potential tie-back candidates. As an example, Aker BP holds an interest in both the Krabbe and Desmond discoveries. Prospectivity in the King Lear area is also high, and further exploration is needed.

IVAR AASEN

Ivar Aasen is Aker BP's digital pilot. As 2018 turned to 2019, the Ivar Aasen team became the first on the Norwegian Continental Shelf to operate a manned platform from an onshore control room.



PRODUCTION 2018

23.5 MBOEPD (net)

PRODUCTION EFFICIENCY

92 %

PRODUCTION START: 2016

The Ivar Aasen platform is now controlled from Aker BP's offices in the centre of Trondheim. The switch was made on 16 January 2019, following a year with careful preparations and testing.

TWO CONTROL ROOMS

Ivar Aasen was constructed with two identical control rooms – on the platform and in Trondheim. The plan has always been to move the control room onshore.

The control room is key to all activity on the platform. Through it, operators monitor facilities, production and equipment and follow up everything that takes place on the field. The control room also plays an important role in activating work permits, and in the arrival of vessels and helicopters within the 500-metre zone.

With an onshore control room, Aker BP sees a considerable potential for increased revenues. The subsurface experts are closer to the control room, and this can give better mutual understanding. Cost cuts can also be achieved over time through the development of new digital solutions that change the way we work.

DRIVING DIGITALIZATION

Ivar Aasen was the first of Aker BP's facilities to introduce handheld devices in the spring of 2018. The offshore operators have been given personal devices which enables easy communication and easy and paperless access to technical documentation and live equipment data. It makes the workday more efficient, more productive and safer.

In August 2018, Aker BP signed a new smart service contract with Framo. The contract provides Framo with real-time access to data on their seawater lift pumps via the Cognite data platform – from Ivar Aasen and two other Aker BP fields.

With the data, Framo can now predict how the pumps will perform in the future. The constant flow of live offshore data supports onshore monitoring of the equipment, which in turn helps to avoid unnecessary scheduled maintenance activities. Framo now focuses on uptime and performance.

WORLD CLASS PLANT AVAILABILITY

On 24 December, Ivar Aasen marked two years in production. And 2018 was another good year for the asset. The operational efficiency was high, with an average plant availability of 97 % – a world class performance.

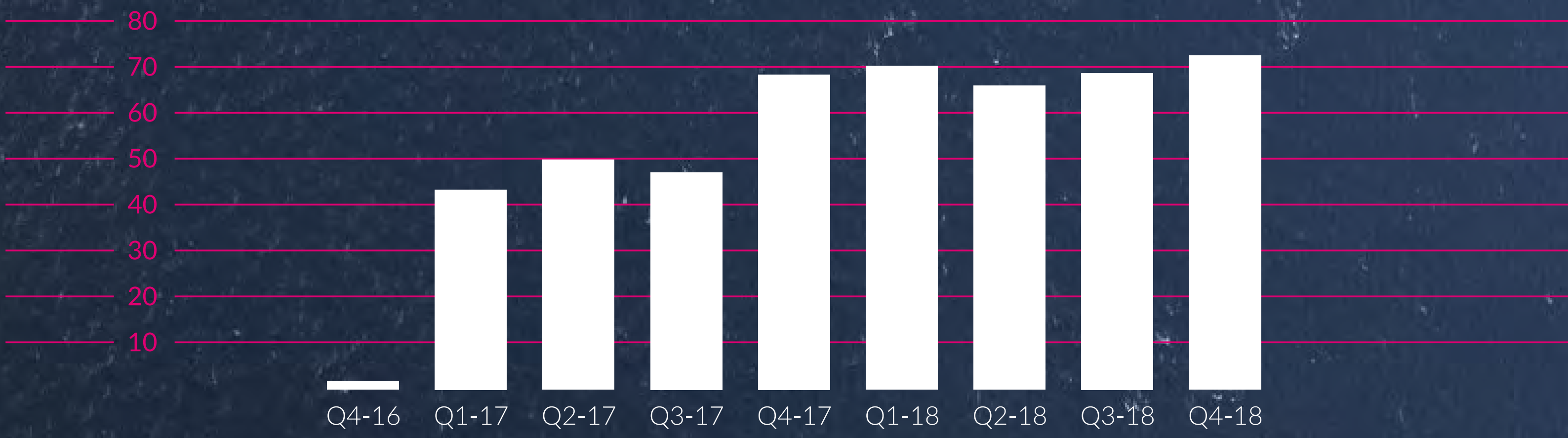
Net production ended on 23.5 mboepd. This is slightly under the production target. The Edvard Grieg field provides Ivar Aasen with power and with processing and export solutions. In 2018, Ivar Aasen production was negatively impacted by power generation issues at Edvard Grieg. This resulted in Ivar Aasen having a production efficiency of 92 % for the year.

Ivar Aasen Area

Producing field
Field development
Discovery
Exploration prospect

Net 2P Reserves: 55 mmboe

Production history (mboepd gross)



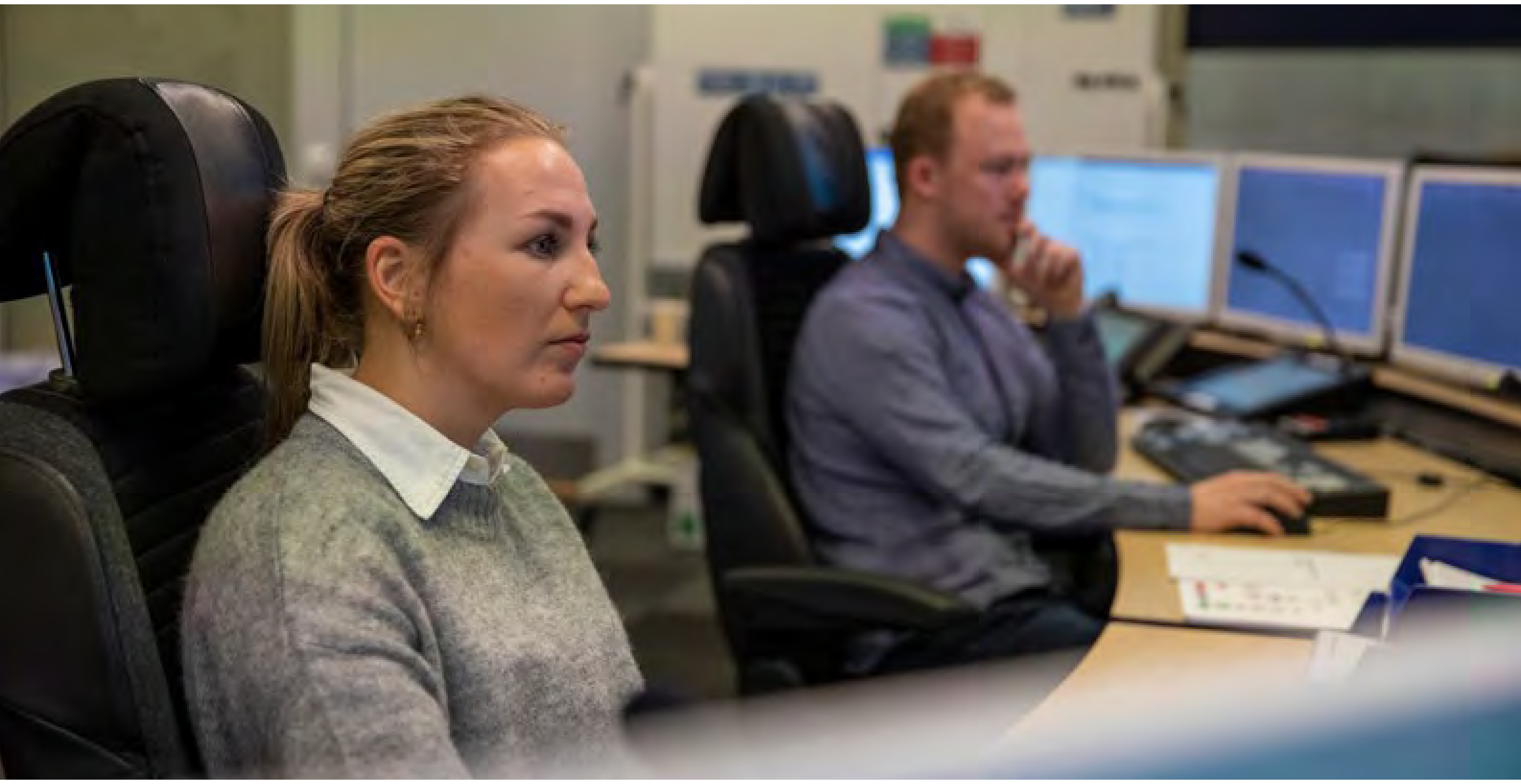
The regularity on Ivar Aasen is expected to increase with a power from shore solution. Ivar Aasen will receive power from shore through the Johan Sverdrup development from 2022. An investment decision was taken by Equinor and the Johan Sverdrup partners in August.

Two new water injectors were successfully completed in the second quarter of the year. The injectors improved our ability to control reservoir pressure development, allowing for a more fine-tuned drainage and resulting in a higher oil/gas ratio.

FUTURE OUTLOOK

Hanz is a possible subsea tie-back to Ivar Aasen. The Hanz appraisal well was drilled in 2018. The well also tested the Slengfehøgda exploration prospect. Aker BP is working to further mature the Hanz development, targeting a start-up in 2022.

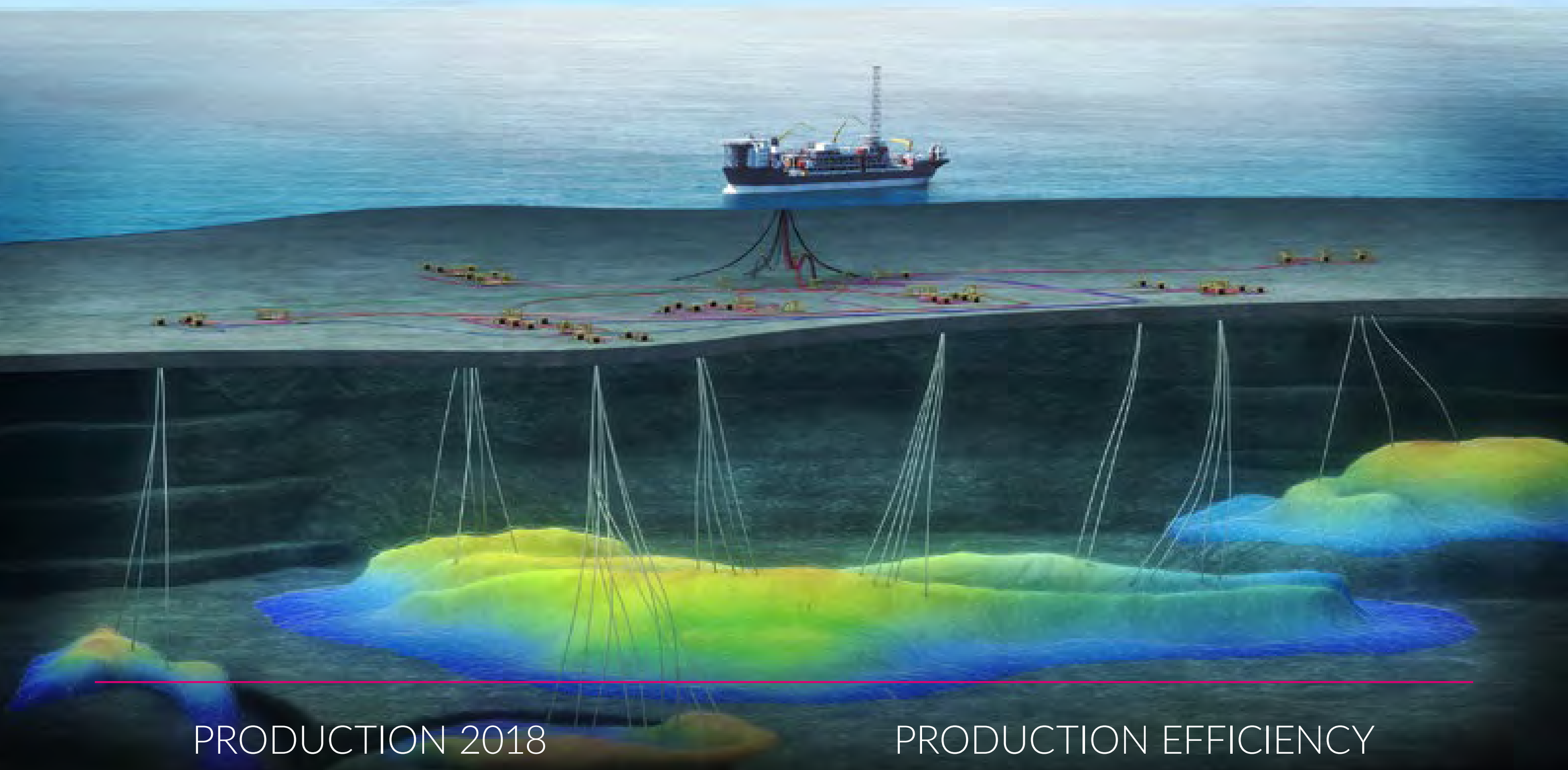
Two new production wells will be drilled in 2019. Aker BP will continue to target opportunities for increased oil recovery in the area to enable stable production going forward.



THE

ALVHEIM AREA

Alvheim can look back at another fantastic year. High and stable production, outstanding production efficiency, new wells on stream and several major discoveries. The Alvheim asset continues to target new opportunities in the area - resulting in a growing resource base.



PRODUCTION 2018

59.6 MBOEPD (net)

PRODUCTION EFFICIENCY

97 %

PRODUCTION START: 2008

The Alvheim asset started 2018 with the first big discovery on the Norwegian Continental Shelf. On 19 February, Aker BP announced an oil discovery in the Frosk exploration well near the Bøyla field. The Frosk discovery contains between 30 and 60 million barrels of oil equivalents.

Less than a year later, on 4 February 2019, Aker BP announced another discovery in the area. The Froskelår main prospect proved oil and gas. The preliminary analysis indicates a gross discovery size within the estimate of 45 to 153 mmboe. A comprehensive data collection programme will be performed to determine the size and quality of the discovery.

GREAT POTENTIAL IN THE FROSK AREA

Aker BP will continue to mature the Frosk development through concept studies before the end of 2019. A Frosk test producer will be drilled in the first half of 2019. The bi-lateral well will gather more information from the Frosk reservoir and will be completed as a test production well.

The test production well is part of an extensive exploration and appraisal program for the Frosk area. The Rumpetroll exploration well will also be drilled in 2019. The area has significant upside potential, and Aker BP evaluates options for a large-scale development of the resources.

400 MILLION BARRELS

In the beginning of August, Alvheim passed 400 million produced barrels of oil equivalents – more than twice the original plan. The Alvheim team reached this milestone ten years after first oil. On average, Alvheim has produced almost 110,000 barrels a day since start-up in 2008.

The production efficiency at Alvheim in 2018 was 97 %. Production was stable and high through the year and ended at 59.6 mboepd (net).

ARRESTING PRODUCTION DECLINE

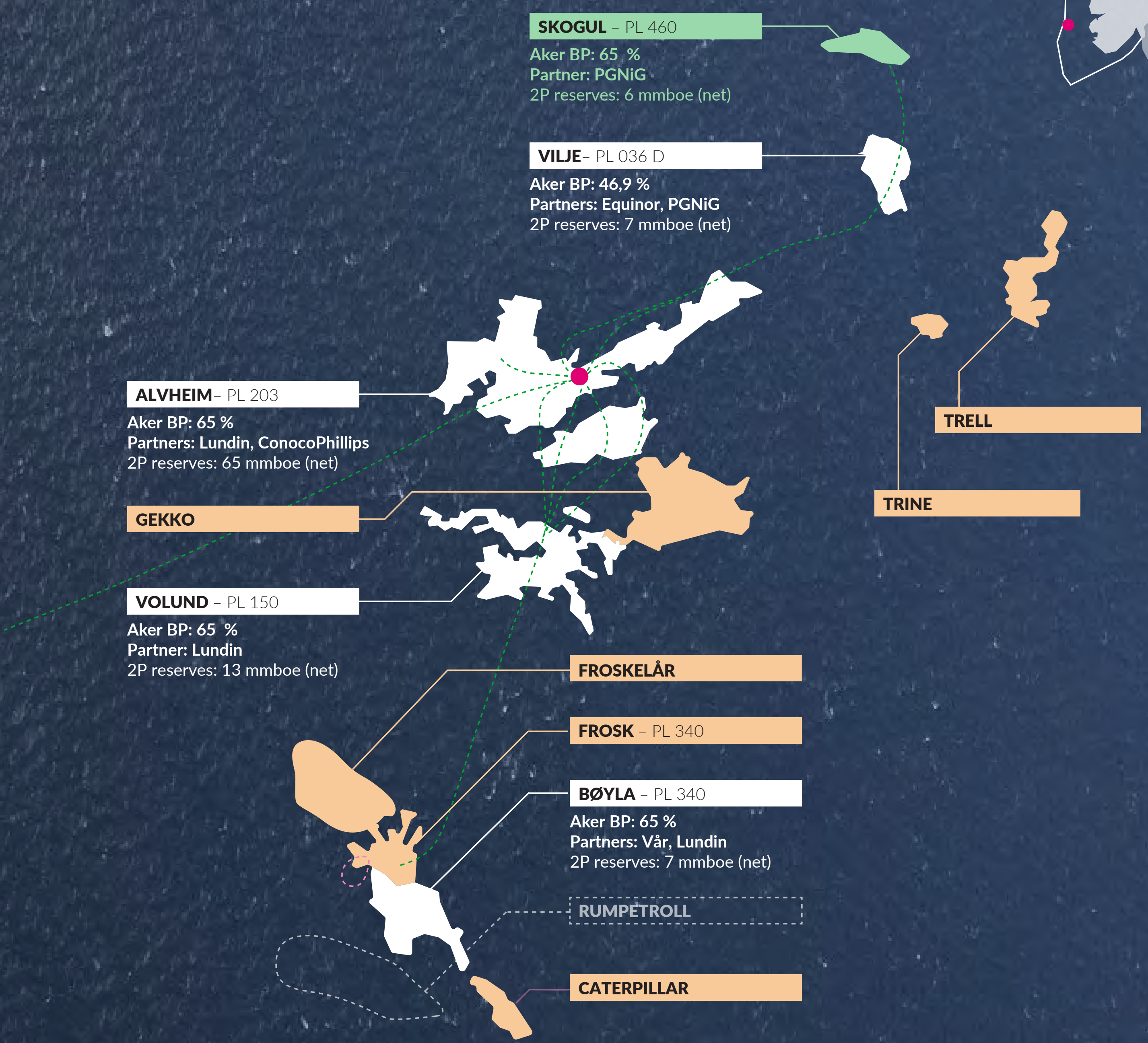
Several new infill wells contributed to high production at Alvheim. In the first quarter of 2018, two new Boa wells came on stream, six weeks ahead of schedule and with higher than expected production volumes.

At the end of the year, the Kamelon Infill South well came on production earlier than planned with an expected 10,000 incremental barrels per day. The tri-lateral well was record-breaking with over ten kilometres drilled in the reservoir. Two of the three laterals represent the longest wells ever drilled and completed in the Alvheim area. The longest one was 3830 metres.

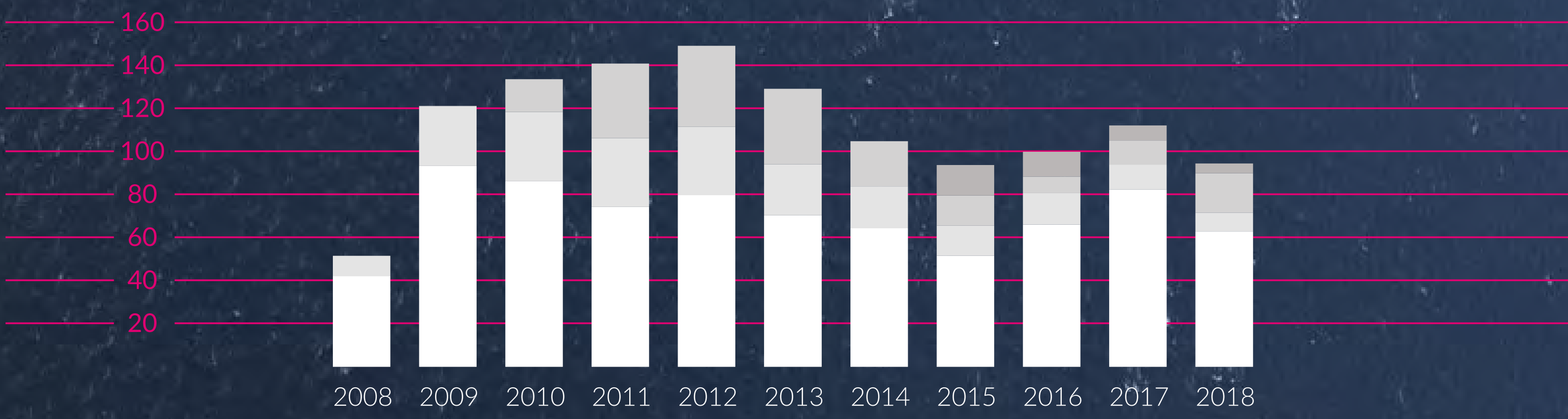
Alvheim Area

Producing field
Field development
Discovery
Exploration prospect

Net 2P Reserves: 99 mmboe



Production history (mboepd gross) ■ Alvheim ■ Vilje ■ Volund ■ Bøyla



The Subsea Alliance with Aker BP, Aker Solutions and Subsea 7 successfully carried out the subsea tie-in for both the Boa and Kameleon Infill South wells. In both deliveries the alliance demonstrated excellent performance. The tie-ins were delivered without serious HSE incidents, faster than planned and at a lower cost compared to traditional tie-in projects.

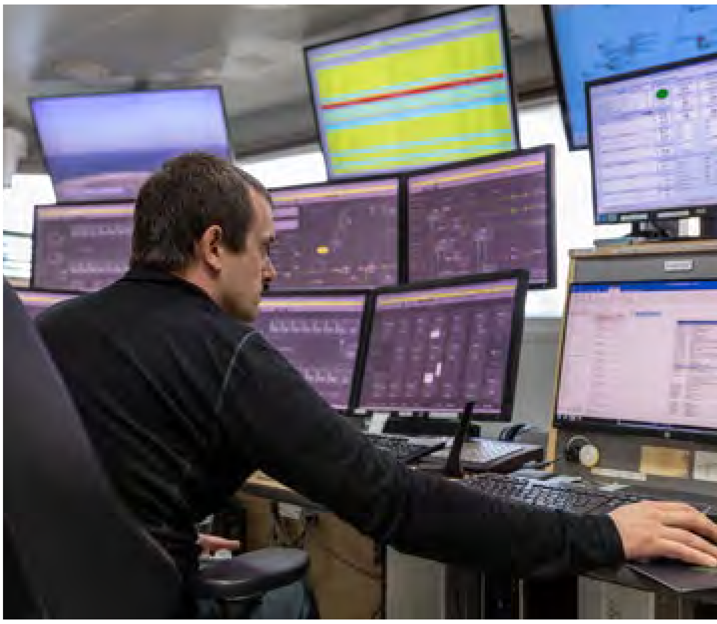
SKOGUL ON TRACK

The Skogul project is on track for start-up in the first quarter of 2020. The field is located 30 kilometres north of Alvheim FPSO and is developed as a subsea tieback via Vilje. Recoverable volumes are estimated to be around 10 million barrels of oil equivalents.

The Subsea Alliance will start installation work in May of this year. The production well will be drilled in the third quarter of 2019.

DIGITALIZING

Handheld devices were rolled out to operators on the FPSO in 2018. The personal devices will provide easy communication, paperless access to technical documentation and live equipment data.



In 2019 Wi-Fi will be installed on the FPSO to support digitalization and enable and increase the functionality of the handheld devices. This will also support a more efficient, productive and safer workday.

FUTURE OUTLOOK

The Norwegian Petroleum Directorate awarded the Alvheim asset and partners the IOR award (Increased Oil Recovery) in 2018. More than half of the oil that Alvheim produces today, comes from discoveries made after production start-up in 2008. And the Alvheim team continues to mature new opportunities in the area. Recovery from Alvheim is optimized using new technology like multilateral wells, 4D seismic surveys and inflow control devices in the wells.

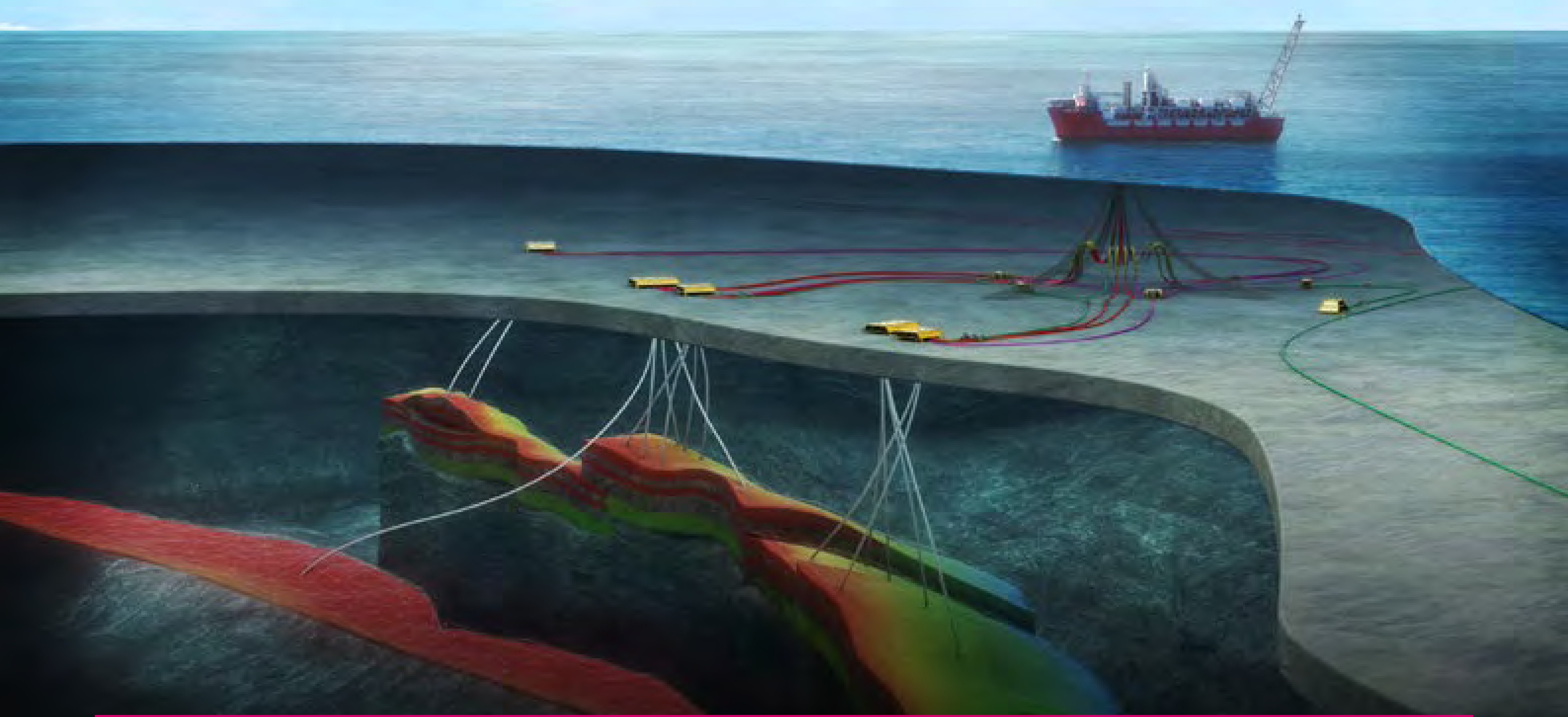
Aker BP has initiated a project which looks at increasing the gas processing capacity on the FPSO and initiated a technology study which reviews the possibility of subsea water separation. Alvheim treats a lot of produced water, and subsea separation would free up more capacity to treat hydrocarbons on the FPSO. Diesel will also be replaced by fuel gas to decrease the environmental footprint from existing boilers.

In July 2018, Aker BP entered into an agreement to acquire 11 licences, including four discoveries, from Total E&P Norge. The deal included the Trell and Trine discoveries in the Alvheim area which are possible future tie-ins to the FPSO.

In the autumn, Aker BP drilled the Gekko appraisal wells. The wells confirmed a resource base of around 40 mmboe and a concept to develop the Gekko field is maturing. The Volund Sidetrack North well will also be drilled in in the first half of 2019. This is a side-track from an existing well on Volund.

THE SKARV AREA

The Ærfugl field will boost production from the Skarv area. In 2018, the first steel in phase 1 of the development project was cut. At the same time the second phase of the project was maturing towards a concept selection – much faster than originally planned.



PRODUCTION 2018

25.2 MBOEPD (net)

PRODUCTION EFFICIENCY

91 %

PRODUCTION START: 2012

Ærfugl is a highly robust and economic development with a break-even price of USD 18.5. Gross reserves are estimated to 268 mmboe. Start-up is expected towards the end of 2020.

Phase 1 of the project is developed with three new production wells tied in to the Skarv FPSO through a 21 kilometres long trace heated pipe-in-pipe flowline. In addition, an Ærfugl test producer is already adding important production to Skarv.

TECHNOLOGICAL BREAKTHROUGHS

The Subsea Alliance between Aker BP, Subsea 7 and Aker Solutions marked the cutting of the first steel in June 2018, two months after the Norwegian Ministry of Petroleum and Energy approved the Plan for Development and Operation (PDO).

Through the autumn, the engineering, procurement and fabrication of the subsea system structure, the wellheads and the vertical Xmas tree system took place on multiple sites across the world. The project progressed according to plan and at year end, approximately 30 % of the phase 1 activities were completed.

The trace heated pipe-in-pipe system is a technological breakthrough. It has been developed by Subsea 7 in collaboration with the manufacturer to deliver leading flowline insulation and enable cost-effective long-distance tie-backs. The remaining technology qualification activities for the pipe system and for a new generation of vertical Xmas trees are on schedule to be ready for construction and assembly in 2019. Offshore modifications on the FPSO will also start in 2019.

ACCELERATING PHASE 2

At PDO submission, total investments in the Ærfugl project was estimated at NOK 8.5 billion (real terms) with NOK 4.5 billion in the first phase and NOK 4.0 billion in the second phase (reference case).

The Ærfugl phase 2 includes two additional wells in the northern part of the Ærfugl field and one in Snadd Outer. Snadd Outer will also be tied back to the Skarv FPSO.

At submission of the PDO, phase 2 was originally set for start-up in late 2023. Now it has been agreed in the licence to accelerate production start with as much as two years. The Ærfugl phase 2 work is now progressing steadily towards a formal concept selection in the second quarter of 2019. Value creation has increased significantly - all made possible by a great team effort.

NEW OPPORTUNITIES

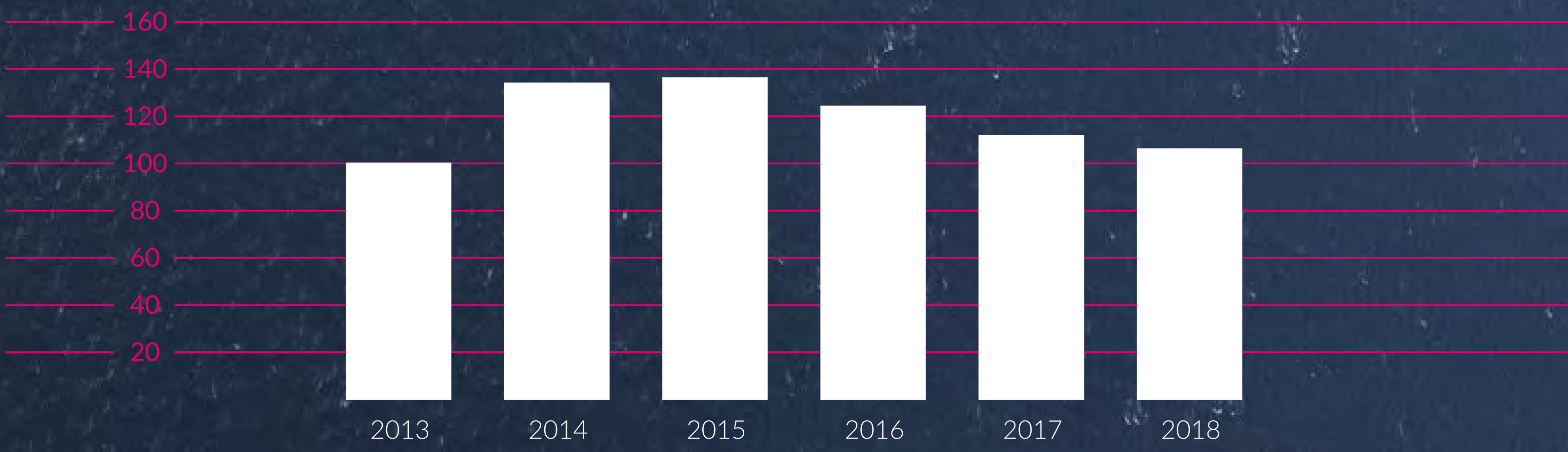
The Ærfugl development will extend the economic field life of the Skarv FPSO and allow for increased recovery from the Skarv field itself. In addition to increasing the gas capacity to full potential by 2024, the development gives new tie-in points north of the FPSO.

Skarv Area

Producing field
Field development
Discovery
Exploration prospect

Net 2P Reserves: 106 mmboe

Production history (mboepd gross)



The Skarv area is still relatively unexplored. In the spring of 2018, Aker BP drilled the exploration well KvitungenTumler, an attractive cretaceous target. Unfortunately, the well turned out to be dry.

In July, 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. One of the discoveries in the portfolio, the Alve Nord, is located north of the Skarv field. It is a possible tie-back to the FPSO. Two very interesting exploration licences were also acquired west of Alve North. A deeper understanding of the area is necessary before a concept is matured further.

PRODUCTION

The production from the Skarv area ended on 25.2 mboepd in 2018 (net). This includes the production from the Ærfugl test production well. Production in 2018 remained stable and high despite challenges with shut-in wells. Production efficiency in 2018 was 91 %.

Well B09 resumed production in late November after successful in-situ repair of the Xmas tree at 400 metres' water depth – a very challenging operation. Leakage from the well was discovered in May, and it was immediately shut down. The cost-saving of the in-situ modification method is great compared to conventional rig operation methods.

FUTURE OUTLOOK

Skarv is one of the major gas producing assets on the Norwegian Continental Shelf. The asset continues to explore opportunities to extend the lifetime of the field beyond 2035. A project launched last year aims to increase the gas capacity on the FPSO. The de-bottlenecking work will be carried out during a major turnaround in 2020.

Operators on the FPSO were given handheld devices in 2018. These devices make the workday more efficient, more productive and safer. The Skarv asset see the potential for further improvements through data collection from approximately 40.000 in- and out-signals and sensors on the FPSO.

Aker BP was awarded three new licences in the Norwegian Sea, of which two as an operator, in the 2018 licensing round for awards in pre-defined areas. A drill decision on the Ærfugl West prospect is expected to be taken during 2019. Aker BP continues to mature the Gråsel and Tilje discoveries. Several concepts are studied.

In 2019, Equinor will drill the Ørn exploration well in the area. PGNIG will drill the Shrek exploration well. Aker BP holds a share in both licences, and discoveries are potential tie-ins to the Skarv FPSO. Aker BP is the operator on the Vågar well, which will be drilled in the second half of 2019.

Aker BP´s Signe Husebø at the first cut of steel for the Ærfugl development project in Sandnessjøen.

Illustration: Try/Equinor

JOHAN SVERDRUP

2018 concluded with the sail-away of the Johan Sverdrup processing platform from South Korea. That milestone ended a very busy year for the Phase 1 development project – where the activity gradually moved from onshore to offshore.

GROSS RESOURCES

2.2–3.2 bn BOE

CURRENT RESERVES

2.7 bn BOE

FIRST OIL: November 2019 – OPERATOR: Equinor – AKER BP INTEREST: 11.57 %
OTHER PARTNERS: Lundin, Petoro and Total

Installation of Norway's longest oil export pipeline from the Johan Sverdrup field to Mongstad with Saipem's Castorone. The total length of the pipe is 283 kilometres (photo: Roar Lindefjeld and Bo Randulff/Equinor)

2018 was a year of offshore installations for the Johan Sverdrup Phase 1 development. The offshore campaign commenced in April with the installation of the jacket for the drilling platform. It was one of the largest offshore installation campaigns ever for the operator, Equinor.

The riser platform was the first of four platforms to be installed in phase one of the project. The riser platform sailed from the Samsung yard in South Korea in February. The topside was constructed in record time and below budget. It was installed on the steel jacket in three modules – also in April.

SMALL CITY RISING

In early May, the offshore organization with employees from Equinor, Aibel, Aker Solutions and other contractors was initiated. In the weeks and months to follow, more than 400 km of pipelines, 200 km of power cables, the drilling platform, two additional jackets and a bridge were installed. A total of 20 wells – 8 oil producers and 12 water injectors – have been pre-drilled.

As many as 800 people were working to hook up and commission the growing field centre. With the riser platform, drilling platform, the Prosafe Safe Zephyrus flotel and Master Marine's jacktel Haven, a small city was rising in the North Sea.

PHASE 2 FINAL INVESTMENT DECISION

At the end of August, the Johan Sverdrup partnership submitted the Plan for Development and Operations (PDO) for the second phase of the Johan Sverdrup field development (the full field development) to the Norwegian Ministry of Petroleum and Energy for approval. Phase 2 consists of a second processing platform, modifications of the riser platform and the field centre as well as five subsea templates, in addition to increased power from shore to the Utsira High. Production start is planned for the fourth quarter in 2022.

At full field plateau, the Johan Sverdrup field will produce up to 660,000 barrels per day, with a break-even price of less than USD 20 per barrel and very low CO_2 emissions, just 0.67 kg per barrel.

The phase 2 PDO also demonstrated further improvements in resources and investment cost. The resource estimate for the entire Johan Sverdrup field has been raised to 2.2-3.2 billion barrels oil equivalents, with an expected estimate of 2.7 barrels. This includes an increased oil recovery contribution from WAG (Water alternating gas injection). The investment cost estimate for Phase 1 and Phase 2 has been further reduced to NOK 86 billion and NOK 41 billion respectively (nominal numbers at project currency exchange rates), a total reduction of 40 % since the Phase 1 PDO estimates in 2015.

POWERED FROM SHORE

On 9 October, the Norwegian Minister of Petroleum and Energy, Kjell-Børge Freiberg, officially opened the Phase 1 power-from-shore solution on the Johan Sverdrup field.

Johan Sverdrup is supplied with power through an onshore converter station at Haugsneset in Rogaland. The electric current is converted from alternating current (AC) to direct current (DC), enabling the transmission of electricity for 200 km offshore with minimum loss. Offshore, the electric current is converted back to the alternating current needed to run the field centre equipment.

In Phase 1 of the Johan Sverdrup development, the power-from-shore solution has a capacity of 100 MW, based on a production capacity of up to 440,000 barrels per day. In phase 2, the power from shore capacity will be expanded with 200 MW, giving a total capacity of 300 MW. The expanded power capacity will give a production capacity of 660,000 barrels per day. This also enables Johan Sverdrup to provide power from shore to the other fields at Utsira High – Edvard Grieg, Gina Krog and Ivar Aasen.

With the power from shore-solution, Johan Sverdrup operations can be run without the use of fossil fuels. Emissions are reduced by an estimated 625,000 tonnes of CO_2 per year, making Johan Sverdrup one of the most carbon-efficient fields worldwide. Another important benefit of power from shore is that it improves the working environment, because the noise offshore is reduced significantly.

THE FINAL PIECES OF THE PHASE 1 PUZZLE

The processing platform arrived in Norway in February 2019. It will make a short stop at Kværner Stord, where two pedestal cranes will be mounted and further preparations will be made. In spring, it will be installed at the Johan Sverdrup field in one single lift by the Pioneering Spirit vessel. After installation of the utility and living quarter platform, closely followed by the last two bridges, the Phase 1 offshore installations are completed.

Full force will then be put on the hook-up and final commissioning activities before expected start-up of oil production in November 2019.

Top photo:
The processing platform left the Samsung Heavy Industries yard on the 18 December - on time, below budget and with no serious incidents. 29,000 tonnes of topsides – fully assembled and tested – started the two-month-long journey to Norway on the world's largest heavy-transport vessel, Boskalis' Vanguard (photo: Equinor).

Middle photo:
Heerema's Thialf installing the riser platform on the jacket which was installed in 2017. Thialf also installed three jackets in 2018 – two from Kværner Verdal and one from Dragados in Cadiz (photo: Bo B. Randulff and Roar Lindefjeld/Equinor).

Bottom photo:
The Norwegian Minister of Petroleum and Energy, Kjell-Børge Freiberg, as he officially opened the Phase 1 power-from-shore solution on the Johan Sverdrup field (photo: Ole Jørgen Bratland/Equinor).

BOARD OF DIRECTORS

ØYVIND ERIKSEN
Chairman

Øyvind Eriksen (born 1964) joined Aker ASA in January 2009. Mr. Eriksen holds a law degree from the University of Oslo. He joined the Norwegian law firm BA-HR in 1990, where he became a partner in 1996 and a director/chairman in 2003. As a corporate attorney he among other things worked with strategic and operational development, M&A and negotiations. Among other, Mr. Eriksen worked closely with Aker.

Mr. Eriksen has held several board positions in different industries, including shipping, finance, asset management, offshore drilling, fisheries, media, trade and industry.

As CEO of Aker ASA Mr. Eriksen is currently chairman of the board in Aker BP ASA, Aker Solutions ASA, Cognite AS, Aker Capital AS and Aker Kværner Holding AS. He is also director of several companies, including Aker Energy AS, Akastor ASA, The Resource Group TRG AS, TRG Holding AS and Reitangruppen AS.

ANNE MARIE CANNON
Deputy Chair

Anne Marie Cannon (born 1957) has over 30 years' experience in the oil and gas sector. From 2000 to 2014, she was Sr. Advisor to the Natural Resources Group with Morgan Stanley, focusing on upstream M&A. She has previously held positions with J Henry Schroder Wagg, Shell UK E&P and with Thomson North Sea.

Ms. Cannon was an executive director on the boards of Hardy Oil and Gas and British Borneo. She also serves on the Board of Directors of Aker ASA. She is a non-executive director of Premier Oil plc and STV Group plc. She is also a non-executive director of Aker Energy AS. She holds a BSc Honours Degree from Glasgow University.

KJELL INGE RØKKE
Board member

Kjell Inge Røkke (born 1958), Aker ASA's main owner, has been a driving force in the development of Aker since the 1990s.

Mr. Røkke launched his business career with the purchase of a 69-foot trawler in the United States in 1982, and gradually built a leading worldwide fisheries business. In 1996, the Røkke controlled company, RGI, purchased enough Aker shares to become Aker's largest shareholder, and later merged RGI with Aker.

Mr. Røkke is currently director of Aker BP, Kvaerner and Ocean Yield.

BOARD OF DIRECTORS

TROND BRANDSRUD
Board member

Trond Brandsrud (born 1958) holds a master's degree from the Norwegian School of Economics. He is board member and non-executive director of several listed and Private Equity owned companies.

Mr. Brandsrud has 30 years' experience from the oil & gas industry. He has served as Group Chief Financial Officer in Aker and Seadrill, and has held a wide range of senior finance positions in Shell, in Norway and internationally.

Recently, he has also held Group CFO and CEO positions in PE owned companies (Lindorff and Lowell) in the financial services sector.

GRO KIELLAND
Board member

Gro Kielland (born 1959) holds an MSc in Mechanical Engineering from the Norwegian University of Science and Technology (NTNU).

Mrs. Kielland has held a number of leading positions in the oil and gas industry both in Norway and abroad, among others as CEO of BP Norway. Her professional experience includes work related to both operations and field development, as well as HSE.

Mrs. Kielland currently serves as an Operational Partner with HitecVision. In addition to her duties and responsibilities at the non-executive level for HitecVision, she also serves as a non-executive Chairman and Director for other companies.

BERNARD LOONEY
Board member

Bernard Looney is the Upstream Chief Executive for BP plc., where he is responsible for exploration, development and production within the Upstream segment.

Mr. Looney joined BP in 1991 as a Drilling Engineer. He has extensive management experience in the oil and gas business, having worked in a variety of locations, including the North Sea, Vietnam, Gulf of Mexico and Alaska. He was appointed to the role of Chief Executive for BP's Upstream Segment in February 2016, is a member of the BP Group Executive Committee and is also a director of several BP Group companies.

BOARD OF DIRECTORS

KATE THOMSON
Board member

Kate Thomson is Group Treasurer for the BP Group, having previously held the position of Group Head of Tax. In her current role, Mrs. Thomson has responsibility for the central financing of the BP Group, providing liquidity to its businesses and optimising value through the management of financial risks at the group level.

Since joining BP in 2004, Mrs. Thomson has held a variety of roles within the Tax function, giving her a deep understanding of the oil and gas industry. As Group Head of Tax, Mrs. Thomson led a global team of tax professionals, developing BP's response to an increasingly challenging fiscal and regulatory environment. Prior to joining BP, she qualified as a chartered accountant with Deloitte. She moved into international tax with Charter plc where she became Head of Tax in 1998, before joining EY in 2001 in M&A tax.

Mrs. Thomson is also a director of several BP Group companies.

INGARD HAUGEBERG
Board member elected by the employees

Ingard Haugeberg (born 1962) is HSE Site Lead on the Ula field, but now serves as a fulltime employee representative. Mr. Haugeberg has broad experience from the Royal Norwegian Air Force in Bodø as an industry mechanic and as department manager for Safelift A/S. He started in Amoco Norge as a mechanic on the Valhall field in 1991. From 1998, he has held several positions in BP Norge.

Mr. Haugeberg has also held a number of different directorships in BP Norge, Industrimaskiner A/S, Global Clean Energy, I/E Media and trippEl A/S. He is trained as an electro-mechanical repairer at the Royal Norwegian Air Force technical school centre in Kjevik and has a company approved bachelor in mechanics.

ANETTE HOEL HELGESEN
Board member elected by the employees

Anette Hoel Helgesen (born 1987) is Operations Engineering Manager for the Ula field. She has been with Aker BP since 2011.

Mrs. Helgesen has held several different positions as process engineer (project, engineering & operations) and onshore operations supervisor for the Valhall Field.

Mrs. Helgesen has a MSc in Chemical Engineering from NTNU, Trondheim.

BOARD OF DIRECTORS

ØRJAN HOLSTAD
Board member elected by the employees

Ørjan Holstad (born 1989) is trained as an instrument technician. Mr. Holstad has been an employee of the company since 2010.

He has both onshore and offshore experience, and project experience form the Skarv FPSO.

Mr. Holstad was member of the BP-Norge AS board of directors from 2015 to 2016. He has been a fulltime employee representative since 2014.

TERJE SOLHEIM
Board member elected by the employees

Terje Solheim (born 1962) is General Manager of Aker BP's Harstad office. He has been with Aker BP since 2013 and has held several positions.

Solheim has an extensive background from the Norwegian Armed Forces, and was one of the founders of Norwegian Petro Services (NPS). He came to Aker BP from Det Norske Veritas (DNV).

EXECUTIVE MANAGEMENT TEAM

KARL JOHNNY HERSVIK
Chief Executive Officer

Karl Johnny Hersvik (born 1972) has been CEO of Aker BP since May 2014. Prior to joining Aker BP, he served as head of research for Statoil. Mr. Hersvik has held a number of specialist and executive positions with Norsk Hydro and StatoilHydro.

Mr. Hersvik holds a Cand. Scient. (second cycle) degree in Industrial Mathematics from the University of Bergen.

DAVID TORVIK TØNNE
Chief Financial Officer

David Torvik Tønne (born 1985) comes from the position of VP Corporate. Controlling in Aker BP. Mr. Tønne has been with the company since January 2017.

Tønne holds a master's degree in finance from NHH Norwegian School of Economics. Prior to Aker BP, he worked for The Boston Consulting Group.

ØYVIND BRATSBERG
Special Advisor

Øyvind Bratsberg (born 1959) joined Aker BP in 2008 as Chief Operating Officer. He has 30 years' experience from several companies in the areas of marketing, business development and operations. Before taking up his position with Det norske (Aker BP), he was responsible for early-phase field development on the Norwegian Continental Shelf for StatoilHydro.

Mr. Bratsberg holds an MSc degree in Mechanical Engineering from NTH, now the Norwegian University of Science and Technology, NTNU.

EXECUTIVE MANAGEMENT TEAM

EVY GLØRSTAD-CLARK
SVP Exploration and Asset Initiation

Evy Glørstad-Clark (born 1975) comes from the position as Asset Development Manager for NOAKA. Ms. Clark has been with the company since 2011.

Glørstad-Clark holds a PhD in Petroleum geology/sedimentology. She has a broad experience as a geologist from BP in Norway and the US. Her PhD focused on seismic stratigraphy, providing stratigraphic control to all sub-projects under PETROBAR, and focused on the Triassic succession in the Barents Sea.

She has held several managerial positions in Aker BP since joining the company.

OLAV HENRIKSEN
SVP Projects

Olav Henriksen (born 1956) joined Aker BP in January 2015. Prior to joining Aker BP, Mr. Henriksen has been working with large development projects in ConocoPhillips since 1990. He has extensive work experience from both Kværner Rosenberg, Kværner Installasjon and ConocoPhillips, including work with large projects such as Ekofisk, Statfjord, Gullfaks, Oseberg and Eldfisk.

Mr. Henriksen has a degree in engineering from Møre og Romsdal Ingeniørhøyskole (the Møre and Romsdal college of engineering).

PER HARALD KONGELF
SVP Improvement

Per Harald Kongelf (born 1959) is responsible for Aker BP's improvement program. Prior to joining Aker BP, Per Harald Kongelf served as head of the Norwegian operations in Aker Solutions.

Mr. Kongelf holds an MSc degree from NTNU in Trondheim and has more than 25 years of industrial experience through numerous technical and management positions in Aker Solutions.

EXECUTIVE MANAGEMENT TEAM

JORUNN KVÅLE
SVP HSSEQ

Jorunn Kvaale (born 1963) comes from the position of Engineering Services Manager, BP Norge. She has extensive experience in the oil and gas industry, including from Amoco and as Offshore Installation Manager for BP Norway.

Mrs. Kvaale is an engineer in Telecommunications and holds a master's degree from BI.

LENE LANDØY
SVP Strategy & Business Development

Lene Landøy (born 1979) comes from the position of VP Strategy, Portfolio and Analysis in Aker BP. Mrs. Landøy has been with the company since January 2017.

Landøy has a master's degree in finance from NHH Norwegian School of Economics/University of California Los Angeles (UCLA). She also holds a master's degree in international finance from the Skema Business School in France.

Prior to joining Aker BP, she led Equinor's business development unit on the Norwegian Continental Shelf.

SVEIN J. LIKNES
SVP Operations and Asset Development

Svein J. Liknes (born 1972) has previously held the position as Skarv Asset Manager. He headed Skarv since the establishment of Aker BP on 1 December 2016. Liknes held a similar role for the Alvheim Asset for Det norske.

Mr. Liknes has broad experience with production units, from both projects and operations, in Asia and Great Britain. He was engaged in the Alvheim project in Norway from 2005.

Liknes has a degree as Master Mariner with a bachelor in Nautical Science from the University of Stavanger and Western Norway University of Applied Sciences.

EXECUTIVE MANAGEMENT TEAM

OLE JOHAN MOLVIG
SVP Reservoir Development

Ole Johan Molvig (born 1972) comes from the position of VP Subsurface, Det norske. He has long experience in the oil and gas industry, mainly from ExxonMobil, Statoil and Marathon Oil.

Mr. Molvig holds a master's degree from NTNU in Trondheim.

TOMMY SIGMUNDSTAD
SVP Drilling & Wells

Tommy Sigmundstad (born 1970) comes from the position of Vice President Wells BP Asia Pacific. Sigmundstad has broad experience within the oil and gas industry from companies such as Baker Hughes and Philips, before joining BP in 2000. Within BP, Sigmundstad has held different operational, engineering and management positions in Norway, the United Kingdom, Azerbaijan and Indonesia.

Mr. Sigmundstad holds a master's degree in petroleum engineering from University of Stavanger.

BOARD OF DIRECTORS' REPORT

BOARD OF DIRECTORS' REPORT

Aker BP continued its positive development in 2018. The financial and operational performance was strong, and the oil and gas reserves and resources increased driven by both organic growth and acquisitions. All major field development projects progressed as planned. Moreover, the company's improvement program is showing tangible results. Aker BP is well positioned to continue to deliver profitable growth and increasing shareholder value in the future.

Aker BP carries out significant operations related to exploration and production of oil and gas on the Norwegian Continental Shelf («NCS»). In addition, the company's development projects involve a wide range of contractors. Health, Safety, Security and Environment («HSSE») and Corporate Social Responsibility («CSR») are of paramount importance to the Board of Directors of Aker BP. Accordingly, the Board recognizes its responsibility for the safety of people and the environment and devotes appropriate time and resources to comply with all regulations and strives to adhere to the highest HSSE standards in the oil and gas industry.

To meet the challenges of an uncertain macro environment and to strengthen its long-term competitiveness, Aker BP has established a strong platform for further value creation. The company leverages an effective business model built on lean principles, strong technological competence and industrial cooperation to ensure safe and efficient operations.

Aker BP has a comprehensive improvement agenda with four focus areas. The aim is to reduce cost and improve efficiency across all disciplines to enable sanctioning of new stand-alone projects at break-even prices below 35 USD/boe. The focus areas are:

1. reorganization of the value chain with strategic partnerships and alliances to remove waste and increase productivity;

2. digitalization of the Exploration & Production («E&P») business model;

3. changing the management systems and culture to build on «Lean» principles by prioritizing flow efficiency over resource efficiency and;

4. to bring these together inside one organization and one business model that withstands volatility and has the flexibility to sustain growth.

Aker BP's net production in 2018 was 155.7 thousand barrels of oil equivalents per day («mboepd»). Total net production volume was 56.8 million barrels of oil equivalents («boe»). About 99 % of the production came from the five operated production hubs; The Alvheim area, Ivar Aasen, the Valhall area, Skarv and the Ula area.

Aker BP continues to be an operator with low carbon emissions intensity. The company's CO_2 intensity target is set at less than 8 kg CO_2 per barrel of oil equivalents (operated fields only). In 2018, the CO_2 intensity was 7 kg CO_2/boe, which is less than half the global average, and below the average for the NCS.

All major field development projects, including Johan Sverdrup, Valhall Flank West and Ærfugl, progressed according to plans. These projects are expected to contribute significantly to the company's production and profitability in the years to come.

The company's exploration activities in 2018 resulted in the Frosk discovery and a positive appraisal of the Gekko discovery. In addition, the company expanded its license portfolio, further strengthening its position as the second largest license holder on the Norwegian Continental Shelf.

Looking forward, the company has a large and robust opportunity set in its existing portfolio. These opportunities represent a potential to triple Aker BP's production by 2025.

Aker BP's 2P reserves increased to 917 (914) mmboe, as the total additions and revisions exceeded the year's production. The company also made two significant acquisitions in 2018, adding 173 mmboe to its 2C contingent resource base. In total, contingent resources grew by 23 percent to 946 mmboe.

The company has a robust and diversified capital structure with USD 3.05 billion in available liquidity as of 31 December 2018. The company paid four dividends in 2018, totaling USD 450 million. Dividends are planned to increase to USD 750 million in 2019, and the Board's stated intention is to increase the annual dividends by another USD 100 million per year until 2023.

Aker BP is well positioned for further value accretive growth on the NCS. The Board is conscious of the risks associated with project execution and the changing market conditions in which the company operates. The Board is prioritizing capital discipline and mitigation of risk wherever possible throughout the organization.

SHARE PRICE PERFORMANCE AND OWNERSHIP STRUCTURE

In 2018, the share price for Aker BP ended at NOK 218.00 per share, compared to NOK 201.90 per share at the end of 2017. At the end of the year, 360.1 million shares were issued, which is the same as at the end of 2017. Aker ASA remains the largest owner with 40 %, while BP P.L.C. controls 30 % of the shares. The remaining 30 % were split among more than 12,000 shareholders. Aker BP is listed on the Oslo Stock Exchange under the ticker symbol «AKERBP».

Business description

DESCRIPTION OF THE COMPANY

Aker BP is a fully-fledged E&P company with exploration, development and production activities on the NCS. Aker BP holds no oil or gas assets outside Norway. All activities are thus within the Norwegian offshore tax regime, and to the extent the company has overseas activities, these are related to construction and engineering of field developments.

Aker BP is active in all three main petroleum provinces on the NCS. The company remains convinced that the NCS offers attractive opportunities for oil and gas exploration and development. This is supported by the NPD's latest undiscovered resources estimates. The company plans to continue to be an active industry player in the coming years.

The company's registered address is at Lysaker in Bærum municipality. The company also has offices in Harstad, Sandnessjøen, Stavanger and Trondheim. Karl Johnny Hersvik is Chief Executive Officer. At the end of 2018, the company had 1,649 (1,371) employees. As operator for 83 (62) licenses and partner in an additional 55 (46) licenses, the company is the second largest license holder on the NCS.

PRODUCTION

As of 31 December 2018, Aker BP had production from 13 fields: Alvheim (65 % and operator), Atla (10 % and partner), Bøyla (65 % and operator), Enoch (2 % and partner), Gina Krog (3.3 % and partner), Hod (90 % and operator), Ivar Aasen (34.786 % and operator), Skarv (23.835 % and operator), Tambar/Tambar East (55/46.2 % and operator), Ula (80 % and operator), Valhall (90 % and operator), Vilje (46.904 % and operator) and Volund (65 % and operator).

Production in 2018 averaged 155.7 mboepd. Approximately 79 % of the production was liquids and 21 % was gas.

Alvheim (65 %, operator) is an oil and gas field operated by Aker BP and is located in the North Sea at a water depth between 120 and 130 metres. The field consists of the Kneler, Boa, Kameleon, East Kameleon, Viper and Kobra structures as well as the Gekko discovery. The Boa reservoir straddles the Norway-UK median line, and is unitized with Verus Petroleum, who is the owner on the UK side. The productive reservoir of the Alvheim field is the middle to late Palaeocene/early Eocene Heimdal and Hermod Formation sandstones, which exist at a depth of approximately 2,100 metres.

Alvheim has been developed using a floating production, storage and offloading (FPSO) vessel, and production started in 2008. The development provides for the transport of oil by shuttle tanker and transportation of gas to the SAGE system. The Alvheim FPSO is also a production host for the satellite fields Volund, Vilje and Bøyla, and for Skogul which is currently under development.

Two new Boa wells and the startup of the Kameleon Infill South well contributed positively to production from Alvheim in 2018. Following the successful appraisal well on the Gekko discovery in 2018, and Aker BP's acquisition of interests in the discoveries Trell and Trine, the company has started the process of integrating these discoveries in the area development plan for the Alvheim area.

Net production from Alvheim, including Boa, averaged 40.7 mboepd in 2018. Production from the Alvheim field is estimated to end in 2033, with subsequent abandonment between 2033 and 2034. Year-end 2018 P50 reserves for Alvheim are estimated at 65 mmboe net to Aker BP.

The **Volund** field (65 %, operator) is located approximately eight km south of Alvheim and was the second field developed as a subsea tieback to Alvheim. The field started producing in 2009 with four production wells and one water injection well. Volund produces oil from Paleocene sandstone in the Hermod Formation.

Net production at Volund averaged 11.8 mboepd in 2018. Production from the Volund field is expected to last until 2033, with subsequent abandonment between 2033 and 2034. Year-end 2018 P50 reserves are estimated at 13 mmboe net to Aker BP.

The **Vilje** field (46.904 %, operator) is located northeast of Alvheim at a water depth of 120 metres. The productive reservoir of the Vilje field is the middle to late Palaeocene Heimdal Formation sandstone at a depth of approximately 2,100 metres. The field is tied back to the Alvheim FPSO. Production commenced in 2008.

Net production from Vilje averaged 4.0 mboepd in 2018. Production from the Vilje field is expected to cease in 2033, with subsequent abandonment between 2033 to 2034. Year-end 2018 P50 reserves are estimated at 7 mmboe net to Aker BP.

The **Bøyla** field (65 %, operator) is located 28 km south of Alvheim at a water depth of 120 metres. The productive reservoir of the Bøyla field is within the Hermod sandstone member, which is a deep marine, channelized submarine fan system at a depth of approximately 2,100 metres. The field is tied back to the Alvheim FPSO. Production commenced in January 2015. The field is developed with two horizontal production wells and one water injection well.

During the first quarter 2018, an oil discovery was made in the Frosk prospect near the Bøyla field. A new well is planned to be drilled in the first half of 2019. This well will gather more information about the reservoir and be completed as a production well which will be used for test production from mid-2019.

Net production from Bøyla averaged 2.9 mboepd in 2018. Production from the Bøyla field is expected to cease in 2033, with subsequent abandonment scheduled to take place between 2033 to 2034. Year-end 2018 P50 reserves are estimated at 3 mmboe net to Aker BP.

The **Valhall** field (90 %, operator) is located in the southern part of the Norwegian North Sea at water depth of 70 metres. The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2,400 metres.

The field was originally developed with three facilities for accommodation, drilling and processing, and started production in 1982. The Valhall complex consists today of six separate steel platforms for living quarters, drilling, wellheads, production, water injection, combined process- and hotel platform respectively. These platforms are bridge-connected. In addition, the field has two unmanned flank platforms, one in the south and one in the north. Additionally, an unmanned west flank platform is being developed and will be operational in 2019. Liquids are routed via pipeline to Ekofisk and further to Teesside in the UK. Gas is sent via Norpipe to Emden in Germany.

Net production from Valhall averaged 35.0 mboepd in 2018. The Valhall concession period currently expires in 2028. The resource potential extends beyond the concession period, and it is common in the industry to achieve extensions to concessions, and the cessation of production will be subject to the technical life of the facilities and the economic cut-off. The current design life for the new Production-Hotel platform (PH) is 2049, 2033 for the Injection Platform (IP) and the Flank North and South, and the Wellhead Platform (WP) has been granted life extension until 2028. Year-end 2018 P50 reserves are estimated at 285 mmboe net to Aker BP.

The **Hod** field (90 %, operator) is located in the southern part of the North Sea. The field was discovered in 1974 and is located 13 kilometres south of Valhall. The water depth in the area is 72 metres. The reservoir lies in chalk in the lower Paleocene Ekofisk Formation, and the Upper Cretaceous Tor and Hod Formations. The reservoir depth is approximately 2,700 metres. The field is developed with a Normally Unmanned Installation, tied back to and remotely operated from Valhall. Hod started producing in 1990.

Net production from Hod averaged 0.9 mboepd in 2018. Hod currently produces from wells drilled from the Valhall Flank South platform. All wells on the Hod platform are currently shut in and awaiting plug and abandon operations. Year-end 2018 P50 reserves are estimated at 4 mmboe net to Aker BP.

The **Ula** field (80 %, operator) is located in the southern part of the North Sea. The water depth in the area is 70 metres. The main reservoir is at a depth of 3,345 metres in the Upper Jurassic Ula Formation.

The development consists of three conventional steel facilities for production, drilling and accommodation, connected by bridges. The field started producing in 1986. The field's gas capacity was upgraded in 2008 with a new gas processing and injection module. The oil is exported via Ekofisk to Teeside and all gas is reinjected into the reservoir to enhance recovery. Ula acts as a third-party host for the Oselvar and Blane fields via subsea tie-backs. Production from the Oselvar tie-back ceased on 1 April 2018 in accordance with agreement. The Spirit Energy operated Oda field is on track to start production during the first half of 2019. Oda is a subsea field which will be tied back to Ula and re-use existing Oselvar inlet facilities on Ula.

Aker BP considers the resource potential in the Ula area to be significant, both from increased oil recovery in the Ula and Tambar fields, from potential tie-backs of other discoveries including the King Lear discovery acquired in 2018, and from exploration opportunities. To unlock this upside potential, the first step in the Ula strategy is to improve the technical condition and extend the expected life of the facilities to ensure stable performance. In parallel, the company is working diligently to mature the opportunity set, which is a complex process involving a broad set of technical and commercial disciplines. This could eventually lead to the addition of a new platform at Ula in the mid-2020s.

Net production from Ula averaged 6.0 mboepd in 2018. The Ula concession period expires in 2028. The resource potential extends beyond the concession period, and it is common in the industry to achieve extensions to concessions, and the cessation of production will be subject to the technical life of the facilities and the economic cut-off. Year-end 2018 P50 reserves are estimated at 39 mmboe net to Aker BP.

The **Tambar** and **Tambar East** field (55.0/46.2 %, operator) is located 16 kilometres southeast of the Ula field in the southern part of the North Sea. The water depth in the area is 68 metres. The reservoir consists of Upper Jurassic sandstones in the Ula Formation, deposited in a shallow marine environment. The reservoir lies at a depth of 4,100-4,200 metres.

The field has been developed with a remotely controlled wellhead facility without processing equipment and started production in 2001. Two new wells on Tambar were put on stream during the first half of 2018. Aker BP is now looking at the potential to optimize the production from the new wells. One important step in the optimization is the start-up of gas lift, which is expected during the spring of this year.

Net production from Tambar averaged 3.4 mboepd in 2018. Year-end 2018 P50 reserves are estimated at 7 mmboe net to Aker BP.

The **Skarv** field (23.8 %, operator) is located about 200 kilometres west of Sandnessjøen in the northern part of the Norwegian Sea. The water depth in the area is 350-450 metres. The reservoirs in Skarv contain gas and condensate in Middle and Lower Jurassic sandstones in the Garn, Ile and Tilje Formations. There is also an underlying oil zone in the Skarv deposit in the Garn and Tilje Formations. The reservoirs lie at a depth of 3,300- 3,700 metres.

Skarv is developed with a production ship with storage and offloading capacity (FPSO) anchored to the seabed. The FPSO has a life expectancy of 25 years. Production started in 2012.

Net production from Skarv, including test production from Ærfugl, averaged 25.3 mboepd in 2018. The Skarv concession period currently expires in 2033 and the original Skarv FPSO design life is 2035. Year-end 2018 P50 reserves are estimated at 39 mmboe net to Aker BP.

The **Ivar Aasen** field (34.8 %, operator) is located in the northern part of the North Sea, about 30 kilometres south of the Grane and Balder fields and consists of the discoveries Ivar Aasen and West Cable. The water depth is 110 metres. The Ivar Aasen reservoir is of

Late Triassic to Middle Jurassic age, and contains oil at a depth of around 2,400 metres. Parts of the reservoir have an overlying gas cap. The reservoir in West Cable is in the Middle Jurassic Sleipner Formation, and contains oil at a depth of around 2,950 metres.

The development comprises a production, drilling and quarters (PDQ) platform with a steel jacket and a separate jack-up rig for drilling and completion. The platform has spare slots for possible additional wells. The platform is prepared for tie-in of a subsea template planned for the development of the Hanz field, and for possible development of other nearby discoveries. First stage processing is carried out on the Ivar Aasen field, and the partly processed fluids are transported to the Edvard Grieg field for final processing and export. Production started in December 2016.

Average daily production net to Aker BP in 2018 amounted to 23.5 mboepd, and net reserves are estimated at 49 mmboe.

The partner operated fields Atla (10 %), Enoch (2 %) and Gina Krog (3.3 %) produced an average of 1.9 mboepd net to Aker BP in 2018. Year-end 2018 P50 reserves net to Aker BP for these fields are estimated at 6 mmboe, mainly related to Gina Krog.

DEVELOPMENT PROJECTS

The total project activity in Aker BP has been very high in 2018, including several major field development projects and offshore modification activity of significant size.

All major field development projects progressed as planned.

Johan Sverdrup (11.5733 % participating interest in unit, partner) is the largest oil discovery on the Norwegian shelf since the 1980s and is located on the Utsira High, 155 km west of Stavanger. The operator estimates the field's recoverable volumes at between 2.2 and 3.2 billion boe.

Phase 1 of the Johan Sverdrup (11.5733 percent) development project is progressing steadily towards planned production start in November 2019. At the end of the fourth quarter, the Phase 1 facilities were approximately 94 percent complete. Offshore hook-up, commissioning and completion of the two platforms installed at the field centre during the early summer continued throughout the fourth quarter.

From early October 2018 the field centre was powered from shore through two 200 km long AC cables. Installation of the gas export pipeline was completed in the fourth quarter. The processing platform construction (P1 topside) was completed in December. Tie-back operations of the eight pre-drilled oil production wells started in December.

Phase 2 of the Johan Sverdrup development is also progressing well. Ongoing activities include detailed engineering and construction preparations at the main construction sites. The Plan for Development and Operations («PDO») for Phase 2 has been submitted to Norwegian authorities and is subject to final approval by the Norwegian Parliament, which is expected by mid-April 2019.

At full field plateau, the Johan Sverdrup field will produce up to 660,000 barrels per day, with a break-even price of less than USD 20 per barrel and very low CO_2 emissions of 0,67 kg per barrel.

The investment cost estimate for Phase 1 and Phase 2 has been reduced to NOK 86 billion and NOK 41 billion respectively (nominal numbers at project FX), a total reduction of 40 % since the Phase 1 PDO estimates in 2015.

At the end of 2018, Aker BP has booked 310 mmboe as net P50 reserves for the Johan Sverdrup full field development, representing 34 % of Aker BP's total P50 reserves.

The partnership consists of Equinor (operator), Lundin Norway, Petoro, Aker BP and Total.

Ærfugl (23.8 %, operator) is a nearly 60 km long and just 2-3 km wide gas condensate field, situated close to the Aker BP-operated Skarv FPSO.

The PDO covers the full-field development and includes the resources in both the Ærfugl and Snadd Outer fields, which are planned to be developed in two phases. The first phase 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 three new wells is expected to begin late 2020.

The second phase of the development is being matured toward Concept Select first quarter 2019. The reference case for the second phase includes two additional wells in the northern part of the field and one additional well drilled from existing Idun template, also tied into the Skarv FPSO, with an estimated production start late 2021.

The PDO was approved by Norwegian authorities in April 2018. Net remaining reserves for Ærfugl are estimated at 67 million barrels of oil equivalents.

Valhall Flank West (90 %, operator) is a project that aims to continue the development of the Tor formation in Valhall on the western flank of the field, with planned startup of operation in fourth quarter 2019. The PDO for Valhall Flank West was approved in March 2018.

Valhall Flank West will be developed from a new Normally Unmanned Installation, tied back to the Valhall field centre for processing and export. Six production wells are planned, with an option to convert two of these wells into water injectors at a later stage. The NUI is going to be fully electrified and will be designed to minimize the need for maintenance activities. The platform will be remotely operated from the Valhall field centre. The net reserves for Valhall Flank West are estimated at 59 million barrels of oil equivalents.

Skogul (65 %, operator) is located 34 kilometres north of Alvheim at a water depth of 110 metres. The productive reservoir is within the Eocene Balder and Frigg formation deep marine deposited sandstone members at a depth of approximately 2,100 metres. The PDO was approved in March 2018, and the field 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. Production is expected to commence first quarter 2020. Aker BP has booked 6 mmboe as net reserves for Skogul.

Oda (15 %, partner) is being developed with a subsea template tied back to the Ula field center via the Oselvar infrastructure. Net recoverable reserves are 7 mmboe and the project is planned to be developed with two production wells and one water injector well, with first oil expected during the first half of 2019. Natural gas from Oda will support the Ula development strategy by providing gas for the WAG injection regime.

In addition to the sanctioned projects, Aker BP have performed detailed studies of development solutions for the NOAKA area. Aker BP's recommendation is to develop the area with a new hub platform in the central part of the area, with processing and living quarters («PQ»). Discussions are still ongoing between the partners on how to develop the NOAKA area.

EXPLORATION

Aker BP's ambition is to be the leading exploration company on the Norwegian continental shelf and to discover 250 mmboe net to Aker BP in the period from 2016 to 2020. This follows the ambition of both long-term reserve replacement and value creation by establishing new core areas with operated production. The company strives to exceed this goal by continuously seeking additional prospect opportunities and improving the available data and technology to create a competitive edge. From 2016 to 2018 the company discovered 119.3 mmboe net to Aker BP.

In 2018, Aker BP participated in 10 exploration wells and 1 appraisal well.

The exploration activity is grouped in two categories; Exploration near own producing fields (Infrastructure led exploration – «ILX») and exploration for growth opportunities (new hubs). Over time, the company is seeking a 60/40 balance between ILX and growth exploration targets.

Exploration drilling tested several new exploration growth options in the Barents Sea, ILX targets in the Skarv, Alvheim, Aasen and Ula areas and growth opportunities in the Tampen Area. A significant discovery was made on Frosk near Alvheim and appraisal drilling on Gekko was also successful. The Barents Sea results however, were disappointing.

Aker BP sees the long-term exploration results as satisfactory, and the ambition to discover 250 mmboe net to Aker BP in the period from 2016 to 2020 remains within reach.

The Frosk discovery opens up a new exploration trend in the Alvheim area which will be further tested in 2019. Mean recoverable Frosk volumes are estimated at 47 million barrels of oil (net to Aker BP 32 million barrels). The Gekko appraisal proved a 6 meters oil rim, and 22 million barrels oil equivalents net to Aker BP was booked.

Aker BP was awarded 11 operated licenses and 10 new partner licenses through Awards in Predefined Areas (APA) 2018 in January 2019. Most of these licenses are located close to the company's existing core areas.

In 2018, total investments in exploration amounted to USD 359 (262) million. Exploration expenses in the Income statement amounted to USD 296 (226) million, including expensed dry wells of USD 66 (75) million, while new capitalized exploration expenditures amounted to USD 129 (112) million.

BUSINESS DEVELOPMENT

In July 2018, Aker BP entered into an agreement with Total E&P Norge to acquire its interest in a portfolio of 11 licenses on the NCS for a cash consideration of USD 205 million. The portfolio included four discoveries with net recoverable resources of 83 mmboe based on estimates from the Norwegian Petroleum Directorate. In addition, the transaction also provided the company with increased equity interest in exploration acreage near the Ula field. The transaction was closed in December 2018.

In October 2018, Aker BP entered into an agreement with Equinor to acquire its 77.8 % interest in the King Lear gas/condensate discovery in the Norwegian North Sea for a cash consideration of USD 250 million. Net recoverable resources in the King Lear discovery are estimated to 77 million barrels oil equivalents («mmboe») according to data from the Norwegian Petroleum Directorate. Aker BP's goal is to develop King Lear as a satellite to Ula, which would 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 a total resource addition of more than 100 mmboe net to the company. The transaction was closed in December 2018.

The annual accounts

All figures in brackets refer to 2017.

The group prepares its financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by EU and the Norwegian Accounting Act.

INCOME STATEMENT

The group's total income amounted to USD 3,750 (2,563) million, which represents an increase of 46 % compared to 2017. Total production volume was 56.8 (50.7) mmboe. The average realized oil price was 72 (56) USD per barrel, while the realized price for natural gas averaged USD 0.29 (0.21) per standard cubic metre («scm»).

Production costs were USD 689 (523) million, equivalent to USD 12.1 (10.3) per barrel of oil equivalent. The increase in production costs was mainly 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 296 (226) million and were mainly related to dry and non-commercial wells, seismic data and general exploration activities.

Depreciation amounted to USD 752 (727) million, which corresponds to a depreciation per barrel of oil equivalent of USD 13.2 (14.3).

Impairments amounted to USD 20 (52) million, of which USD 25 million was related to Gina Krog, while there was a reversal of impairment of USD 5 million on other assets. A breakdown of the impairment charges is included in Note 13 to the financial statements.

Other operating expenses amounted to USD 17 (28) million. The majority of other operating expenses are relating to preparation for operation, non-license related costs and IT costs.

The company reported an operating profit of USD 1,975 (1,007) million. The pre-tax profit amounted to USD 1,805 (811) million, and the tax expense on the ordinary profit amounted to USD 1,328 (536) million.

The tax rules and tax calculations are described in Notes 1 and 10 to the financial statements.

The after-tax profit was USD 476 (275) million.

STATEMENT OF FINANCIAL POSITION

Total assets at year-end amounted to USD 10,777 (12,019) million.

Equity amounted to USD 2,990 (2,989) million at the end of 2018, corresponding to an equity ratio of 28 (25) percent.

At 31 December 2018, gross interest-bearing debt was USD 2,018 (3,389) million, consisting of the DETNOR02 bond of USD 224 million, the AKERBP Senior Notes (17/22) of USD 393 million, the AKERBP Senior Notes (18/25) of USD 493 million, and the Reserve Based Lending («RBL») facility of USD 908 million. A bank term loan of USD 1,500 million was repaid during the fourth quarter 2018 following the refund of the tax loss related to the Hess Norge acquisition.

At the end of the year, the company had total available liquidity of USD 3.1 (2.9) billion, comprising USD 45 (233) million in cash and cash equivalents, and USD 3,050 (2,670) million in undrawn credit facilities. For information about terms on the credit facilities, see Note 23.

CASH FLOW AND LIQUIDITY

Net cash flow from operating activities amounted to USD 3,800 (2,155) million. This included tax refunds excluding interest of USD 1,513 (405) million.

Net cash flow used in investment activities amounted to USD 2,147 (3,059) million. The main items were investments in fixed assets of USD 1,313 (977) million, and net payments of USD 463 million related to license acquisitions.

At the end of 2018, financial covenants for the company's debt instruments were comfortably within applicable thresholds. The company has a robust balance sheet with USD 3.1 (2.9) billion in available liquidity, providing the company with ample financial flexibility. The company is continuously working to improve the efficiency and effectiveness of its capital and debt structure.

CHANGES IN ACCOUNTING STANDARDS

The applied accounting principles are in all material respects the same as for the previous financial year.

Two new accounting standards came 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 do not impact any line items in the balance sheet or have any impact on reported cash flows.

Some accounting standards have been issued but not adopted as of 31 December 2018 (IFRS 16) and the potential impact on the accounts are described in note 1.

There are no material changes in the presentation in the income statement for 2018 compared to 2017.

HEDGING

The company seeks to reduce the risk related to foreign exchange rates, interest rates and commodity prices through hedging instruments.

For 2018, the company had put options in place for a volume equivalent to approximately 75 % of its oil production post tax. At year-end 2018, the company had purchased oil put options with strike prices of USD 55 per barrel for 23 % of its expected oil production for the first half of 2019, corresponding to 83 % of the after-tax value.

THE GOING CONCERN ASSUMPTION

Pursuant to the Norwegian Accounting Act section 3-3a, the Board of Directors confirms that the requirements of the going concern assumption are met and that the annual accounts have been prepared on that basis. The Board considers the financial position and the liquidity of the company to be good. The company is continuously considering various sources of funding to facilitate the expected growth of the company. Cash flow from operations, combined with available liquidity of USD 3.1 billion is expected to be more than enough to finance the company's commitments in 2019.

In the Board of Directors' view, the annual accounts give a true and fair view of the company's assets and liabilities, financial position and results. The Board of Directors is not aware of any factors that materially affect the assessment of the company's position as of 31 December 2018, or the result for 2018, other than those presented in the Board of Directors' Report or that otherwise follow from the financial statements.

RESOURCE ACCOUNTS

Aker BP complies with guidelines from Oslo Stock Exchange and the Society of Petroleum Engineers' (SPE) classification system for quantification of petroleum reserves and contingent resources. Total net P90/1P reserves are estimated at 683 (692) mmboe, while net P50/2P reserves amounted to 917 (914) mmboe at year-end 2018. See Note 29 for a more detailed review of the resource accounts. The reserves have been certified by an independent third party.

PROFIT FOR THE YEAR

The Board of directors proposes that the profit for the year is transferred to other equity.

HSSE and organization

Health, Safety, Security and 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.

HEALTH, SAFETY AND THE ENVIRONMENT IN AKER BP'S OPERATIONS

Aker BP shall be a safe workplace, where the goal is to prevent any kind of harm. Everyone who works for the company – our employees, hired personnel and contractors – shall be able to perform their work in an environment where the emphasis is on safety. Our facilities shall be in good condition, and must be planned, designed and maintained in a manner that ensures their technical integrity.

During 2018, Aker BP had three HSSE events with high potential – two involving dropped objects that resulted in material damage and one incident during testing of the walkway from a vessel to Tambar (W2W - Walk to Work). The walkway missed the landing point, and hit and broke the handrail, cable trays and lighting fixtures. No personnel were injured. Learnings from the incident are implemented in the ongoing W2W project on Valhall Flank West.

In January, the company had a gas detection and hydrocarbon leak in a slop tank on the Alvheim FPSO, classified as a Process Safety Event Tier 1. The incident was thoroughly investigated according to procedures and lessons learned were implemented – as for all relevant HSSE events throughout the year. The Total Recordable Injuries Frequency (TRIF) for 2018 was 2.98, compared to 2.94 in 2017. However, the number of serious injuries was significantly lower than last year.

The planned improvement activities in the company's 2018 HSSE program have been completed and new HSSE programs for 2019 have been issued for each asset.

The Petroleum Safety Authority (PSA) carried out 19 audits of Aker BP operations and activities in 2018 (16 audits in 2017). Other authorities such as the Norwegian Environmental Agency, the Norwegian Radiation and Nuclear Safety Authority etc. conducted nine audits in 2018 (eight audits in 2017).

Aker BP received a notice of order for Ula from the PSA related to the audit «Risk, barrier and maintenance management» in 2018. Aker BP complied with the order by the deadline 1 March 2019. In addition, Aker BP is conducting a large work program to rejuvenate the facilities at Ula in order for it to continue to be a safe and reliable operating hub for the coming decades.

Security

Aker BP divides security into three main areas: personnel, object and information security. The company work within these areas to protect the company's values in accordance with relevant legislation and company needs. This work is also an integrated part of Aker BP's risk and barrier management.

Security differs from safety by focusing solely on unwanted events caused by intentional actions. Through intelligence, value and threat assessments, as well as by raising awareness in the company, we work to ensure that neither our business nor our personnel are directly affected by threat agents.

In 2018, we have worked to align our systematic security work with the revised company needs; efforts include establishing a common corporate security culture, strengthening cyber security awareness and making sure we maintain knowledge and insight of current and future security risks. Going forward, we will be committed and working as one team to become leading with regard to Security.

Climate strategy
In 2018, Aker BP formally integrated and embedded climate into our strategy and decision making. Our climate road map shows our strategic priorities to ensure that we continuously improve by reducing our emissions and implementing energy efficiency in our operations. The Board of Directors have ownership of climate related objectives and expectations in Aker BP's climate strategy, and reviews and guides the major plans of action when it comes to investment decisions for climate initiatives. Our CO_2 intensity target is set at less than 8 kg CO_2 per barrel of oil equivalents (operated fields only). In 2018 our CO_2 intensity was 7 kg CO_2/boe, which is less than half the global average, and below the average for the NCS. Aker BPs improvement agenda includes energy management, and the implementation of energy efficiency and emission reduction measures.

As part of the Aker BP climate strategy, we established an energy forum in 2017 and intensified the work across the organization in 2018. Members from various business units in Aker BP are involved in the forum and act as driving forces for the energy efficiency and optimization work, as well as emission reduction initiatives.

Power from shore (hydro power) is part of the active energy management within the company, and in 2018 several feasibility studies were performed for existing fields in relation to life extension. Valhall already has power from shore and Ivar Aasen will receive power from shore in 2022. In 2018 Aker BP set the «Field of the Future» ambitions for new developments, covering elements such as renewable power, use of zero emission technology and high degree of digitalization.

EMPLOYEES AND WORKING CONDITIONS
Status of employees and recruitment
- At year-end 2018, the company had 1649 (1371) employees.
- Aker BP recruited 323 new employees and 12 apprentices in 2018.
- Aker BP has a long-standing collaboration with graduate schools and universities to recruit talent as well as cooperation with regards to student internships.

Equal opportunities
The company endeavors to maintain a working environment with equal opportunities for all based on qualifications, irrespective of gender, ethnicity, sexual orientation or disability.

In December 2018, women held 21 % of the positions in the company. The share of women on the Board of directors was 37 %. The share of women in the executive management team was 20 % and in the middle management it was 21.5 %.

Men and women with the same jobs, with equal professional experience who perform equally well, shall receive the same pay in Aker BP. The complexity of the job, discipline area and number of years of work experience affect the pay level of individual employees.

At year-end, 9.2 % of the employees were of non-Norwegian origin.

The working environment
Aker BP has a working environment committee (AMU) as described in the Norwegian Working Environment Act. The committee plays an important role in monitoring and improving the working environment and in ensuring that the company complies with laws and regulations in this area.

The company is committed to maintaining an open and constructive dialogue with the employee representatives and has arranged meetings on a regular basis throughout the year. Four local trade unions are registered as being represented in the company; Tekna, Lederne, SAFE and Industri Energi.

In the Board's view, the working environment in Aker BP during 2018 was good. This was confirmed through employee satisfaction surveys conducted during 2018, where results showed consistent scores over time on questions related to working environment.

Sickness absence

In 2018, the total sickness absence in Aker BP was 2.8 %. For onshore personnel the figure was 2.0 %, which is very low. For offshore personnel, the figure was 5.0 %, which is comparable with other operators and lower than onshore industry.

Ethics and Integrity

Aker BP's values are Enquiring (Søkende), Responsible (Ansvarlig), Predictable (Forutsigbar), Committed (Engasjert) and Respectful (Respektfull). The Norwegian words make out the abbreviation SAFER. The values define the company culture and describe how we want to work in Aker BP. The values also guide our behaviour in the workplace and enable us to live by our Code of Conduct. Our goal is that every employee habitually acts according to our core values.

Aker BP's Code of Conduct sets out requirements for good business conduct and personal conduct for all employees of Aker BP and members of its governing bodies. The code also applies to directors, contract personnel, consultants and others who act on Aker BP's behalf. It has been developed in dialogue with the management group and is anchored with the Board of Directors. The Code of Conduct is available on our intranet and website.

Social Responsibility

Aker BP works to create value for all key stakeholders, including local communities where we operate, by integrating social responsibility into the way we do business. We partner with local businesses, organizations and authorities to achieve mutual understanding of expectations, facilitate direct and indirect local benefits and create opportunities for stakeholders.

Stakeholder engagement

Open and proactive dialogue with stakeholders facilitates our ability to access the resources we require through the whole life cycle of our assets.

We work with governments, communities and non-governmental organizations to implement social investment programs that can have a sustainable beneficial impact. We invest in community projects that align with local needs and our business activities.

When planning projects, we assess the potential impacts on communities. This helps to identify early on whether any activities could affect stakeholders or the environment in nearby communities, and to find ways to prevent or mitigate those impacts. We consult with communities, so that we can understand their expectations and address concerns. Through this, we hope to resolve potential disagreements, avoiding negative impacts on others and disruption to our activities.

Local business and community benefits

Aker BP is committed to creating jobs and growing local businesses in the communities in which the Company operates.

All five operated hubs; Alvheim, Valhall, Ula, Ivar Aasen and Skarv, have performed and secured acceptance for the impact assessment studies as part of the Government approval process. According to the Government's Northern Area Policy, special focus should be given to the development and operation of fields located in Northern Norway to help stimulate local content and create value in the regions. Our Ærfugl development field, located offshore west of Helgeland, is in this category.

Aker BP has continued the contract strategy from Skarv to the Ærfugl development, where the Company keep focus on four elements to stimulate local engagement and value creation;

1. Maximizing the local impacts
2. Decentralized contracts
3. Local procurement function and active supplier development
4. Close contact and cooperation with Nordland County, local municipalities in Helgeland, business, schools and educational institutions.

Supplier/vendor seminars and one-to-one meetings have been conducted, focusing on how local businesses can position themselves to win contracts. Splitting up contracts in sizes manageable for local businesses and their capacity, has given them the opportunity to compete in tendering processes.

Aker BP is a member of the Oil and Gas Cluster Helgeland and Petro Arctic, both organizations located in Northern Norway with key focus on how to involve local and regional business enterprises.

To stimulate the cooperation with schools and education, Aker BP is supporting activities and public offices that contribute to the growth and development of the local community by offering studies, competence-raising measures and innovation processes and projects such as «Kunnskapsparken Helgeland», «Tverrfaglig Opplæringskontor», «Studiesenter Tverrfaglig Opplæringskontor», «Studiesenter Ytre Helgeland», «Kunnskapsutvikling Helgeland» and «Sandnessjøen upper secondary school».

Aker BP is further developing the cooperation agreement with Nordland County focusing on local business development, schools and education.

RESEARCH AND DEVELOPMENT

The aim of Aker BP's Research & Development (R&D) efforts is to support our journey to become the leading independent offshore E&P company. We invest in R&D across our whole value chain, and we have a balanced portfolio of projects targeting knowledge and methods, physical technology development, and digital / software development. We led or participated in around 100 projects in 2018 with a total spend amounting to NOK 430 million. This is a significant increase in activity level from 2017, in line with our company's growth. While we work on a broad range of topics, we have a set of strategic priorities to guide our investments:

- Increased understanding of subsurface and digitalization
- Direct link to our corporate strategy, either directly supporting our activities or creating intangible values (knowledge, methods and processes) that provide a competitive advantage
- Sizeable projects with momentum, dedicated people, with significant impact potential

With our current business plan, we see several areas where research and technology development will support resource growth and recovery, ensure safe operations, lower cost, and minimize the climate footprint. Some highlights from our R&D portfolio are:

- Continuing our development of a platform for acquisition, processing and storage of data from industrial sensors, meeting big data, robotics and machine learning challenges
- Researching new types of unmanned and remote-controlled facilities
- Seismic imaging and processing based on full waveform inversion
- Developing software for establishing and managing barrier strategies and status, including process safety, drilling and wells, logistics, information management and more
- Developing wired pipe systems with two-way high speed signal communication and transfer of electrical power to downhole tools

CORPORATE GOVERNANCE
Aker BP believes that good corporate governance with a clear distribution of roles and responsibility between the owners, the Board and executive personnel is crucial for the company to deliver value to its shareholders.

The Board of Aker BP is responsible for maintaining the highest corporate governance standards. The Board carries out an annual review of the company's principles. The company complies with relevant rules and regulations for corporate governance, including the most recent version of the Norwegian Code of Conduct for Corporate Governance, published on 17 October 2018, unless otherwise specified.

An account of corporate governance is provided in a separate section of the annual report and on the company's website www.akerbp.com.

The company has emphasized providing accurate information in interim reports, capital market days and through direct dialogue with relevant authorities.

REPORTING OF PAYMENTS TO GOVERNMENTS
Aker BP has prepared a report on government payments in accordance with the Norwegian Accounting Act § 3-3 d) and the Norwegian Securities Trading Act § 5-5a. It states that companies engaged in activities within the extractive industries shall annually prepare and publish a report containing information about their payments to governments at country and project level. The report is provided in a separate section of the annual report and on the company's website www.akerbp.com.

Risk factors

RISKS RELATING TO THE OIL AND GAS INDUSTRY

- **Aker BP's business, results of operations, cash flow and financial condition depend significantly on the level of oil and gas prices and market expectations of these, and may be adversely affected by volatile oil and gas prices and by the general global economic and financial market situation**

The company's profitability is determined in large part by the difference between the income received from the oil and gas produced and the operational costs, taxation costs relating to recovery (which are assessable irrespective of sales), as well as costs incurred in transporting and selling the oil and gas. Lower prices for oil and gas may thus reduce the amount of oil and gas that the company is able to produce economically. This may also reduce the economic viability of the production levels of specific wells or of projects planned or in development to the extent that production costs exceed anticipated revenue from such production.

The economics of producing from some wells and assets may also result in a reduction in the volumes of the company's reserves. Aker BP might also elect not to produce from certain wells at lower prices. These factors could result in a material decrease in net production revenue, causing a reduction in oil and gas acquisition and development activities. In addition, certain development projects could become unprofitable because of a decline in price and could result in the company having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact.

In addition, a substantial material decline in prices from historical average prices could reduce the company's ability to refinance its outstanding credit facilities and could result in a reduced borrowing base under credit facilities available to the company, including the RBL facility. Changes in the oil and gas prices may thus adversely affect the company's business, results of operations, cash flow, financial condition and prospects.

- **Exploration, development and production operations involve numerous safety and environmental risks and hazards that may result in material losses or additional expenditures**

Developing oil and gas resources and reserves into commercial production involves risk. Aker BP's exploration operations are subject to all the risks common in the oil and gas industry. These risks include, but are not limited to, encountering unusual or unexpected rock formations or geological pressures, geological uncertainties, seismic shifts, blowouts, oil spills, uncontrollable flows of oil, natural gas or well fluids, explosions, fires, improper installation or operation of equipment and equipment damage or failure. Given the nature of offshore operations, Aker BP's exploration, operating and drilling facilities are also subject to the hazards inherent in marine operations, such as capsizing, sinking, grounding and damage from severe storms or other severe weather conditions, as well as loss of containment, fires or explosions.

- **The market in which Aker BP operates is highly competitive**

The oil and gas industry is very competitive. Competition is particularly intense in the acquisition of (prospective) oil and gas licenses. Aker BP's competitive position depends on its geological, geophysical and engineering expertise, financial resources, the ability to develop its assets and the ability to select, acquire, and develop proven reserves.

- **Climate change regulation could have negative effect on the company**

The company's business and results of operations could be adversely affected by climate change and the adoption of new climate change laws, policies and regulations. Growing concerns about climate change and greenhouse gas emissions have led to the adoption of various regulations and policies, including the Paris Agreement negotiated at the 2015 United Nations Conference on Climate Change («COP 21»), which requires participating nations to reduce carbon emissions every five years beginning in 2023. Multiple plans have also been proposed in the Norwegian parliament to reduce carbon emissions from companies operating in certain sectors, including the oil and gas industry, and create a carbon trading system linked to the European Union's emissions trading scheme.

The emission reduction targets and other provisions of the recent Norwegian climate change law, the Paris Agreement, or similar legislative or regulatory initiatives enacted in the future, could adversely impact the company's business by imposing increased costs in the form of taxes or for the purchase of emission allowances, limiting the company's ability to develop new oil and gas reserves, decreasing the value of its assets, or reducing the demand for hydrocarbons and refined petroleum products.

Climate changes could potentially have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Aker BP's offshore operations could be at risk from such climatic events

RISKS RELATING TO THE BUSINESS OF THE COMPANY

- **Aker BP's current production and expected future production is concentrated in a few fields**

Aker BP's production of oil and gas comes from a limited number of offshore fields. If mechanical or technical problems, abnormal weather or other events affect the production on one of these offshore fields, it may have direct and significant impact on a substantial portion of the company's production. Also, if the actual reserves associated with any one of these fields are less than the estimated reserves, the company's results from operations and financial condition could be materially adversely affected.

- **There are risks related to redetermination of unitized petroleum deposits**

Unitization agreements relating to production licenses may include a redetermination clause, stating that the apportionment of the deposit between licenses can be adjusted within certain agreed time periods. Any such redetermination of interest in any of the company's licenses may have a negative effect on its interest in the unitized deposit, including its tract participation and cash flow from production. No assurance can be made that any such redetermination will be satisfactorily resolved, or will be resolved within reasonable time and without incurring significant costs. Any redetermination negatively affecting the company's interest in a unit may have a material adverse effect on its business, results of operations, cash flow, financial condition and prospects

- **Development projects are associated with risks relating to delays and costs**

Aker BP's ongoing development projects involve advanced engineering, extensive procurement activities and complex construction work to be carried out under various contract packages at different locations onshore. Furthermore, the company (together with its license partners), must carry out drilling operations, install, test and commission offshore installations and obtain governmental approval to take them into use prior to commencement of production. The complexity of such development projects makes them sensitive to circumstances that may affect the planned progress or sequence of the various activities, as this may result in delays or cost increases.

Although Aker BP believes that the development projects will be completed on schedule in accordance with all license requirements and within the estimated budgets, the current or future projected target dates for production may be delayed and cost overruns may incur.

Furthermore, estimated exploration costs are subject to a number of assumptions that may not prove to be correct. Any such inability to explore, appraise or develop petroleum operations or incorrect assumptions regarding exploration costs may have a material adverse effect on the company's growth ambitions, future business and revenue, operating results, financial condition and cash flow.

- **Aker BP is subject to third-party risk in terms of operators and partners**

Where Aker BP is not the operator of a license, although it may have consultation rights or the right to withhold consent in relation to significant operational matters depending on the level of its interest in such license (as most decisions by the management committee only require a majority vote), the company has limited control over management of the assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action may result in significant delays, losses or increased costs to Aker BP.

- **Aker BP is subject to third-party risk in terms of contractors**

Market conditions may impair the liquidity situation of contractors and consequently their ability to meet its obligations towards Aker BP. This may in turn impact both project timelines and cost.

- **Oil and gas production could vary significantly from reported reserves and resources**

Aker BP's reserve evaluations have been prepared in accordance with existing guidelines. These evaluations include many assumptions relating to factors such as initial production rates, recovery rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and gas, operating costs, and royalties and other government levies that may be imposed over the producing life of the reserves and resources. Actual production and cash flows will vary from these evaluations, and such variations could be material. Hence, although the company understands the life expectancy of each of its assets, the life of an asset may be shorter than anticipated. Among other things, evaluations are based, in part, on the assumed success of exploration activities intended to be undertaken in future years. The reserves, resources and estimated cash flows contained in such evaluations will be reduced to the extent that such exploration activities do not achieve the level of success assumed in the evaluations, and such reductions may have a material adverse effect on the company's business, results of operations, cash flow and financial condition.

- **Aker BP may become a target of cyber-attacks**

The company could be a target of cyber-attacks designed to penetrate the security of its network or internal systems, misappropriate proprietary information, commit financial fraud and/or cause interruptions to the company's activities, including a reduction or halt in production. Such attacks could include hackers obtaining access to company systems, the introduction of malicious computer code or denial of service attacks. Such actual or perceived breaches of network security could adversely affect the company's business or reputation, and may create exposure to the loss of information, litigation and possible liability.

- **Changes in taxation and regulations for the petroleum industry**

There is no assurance that future political conditions in Norway will not result in the government adopting different policies for petroleum taxation. In the event there are changes to this tax regime, it could lead to new investments being less attractive and challenge further growth of the company.

Furthermore, the amounts of taxes could also change significantly as a result of new interpretations of the relevant tax laws and regulations or changes to such laws and regulations. In addition, tax authorities could review and question the company's tax returns leading to additional taxes and tax penalties which could be material.

The Norwegian Government is currently implementing a tax reform in Norway. The tax reform has, inter alia, led to a reduction in the general corporate tax rate, while the special petroleum tax rate has been increased. The overall effect of the rate changes for the petroleum sector is that the total marginal tax rate of 78 % has remained unchanged. Further tax reform may result in changes in the Norwegian tax system (which may include changes in the tax treatment of interest costs and to withholding taxes) that may affect our current and future tax positions, net income after tax and financial condition.

Separately, within the current tax regime the Norwegian tax authorities may take a different view from the company as to whether costs qualify as deductible exploration costs eligible for a tax refund or the law may change as to what costs qualify as deductible exploration costs or whether a tax refund may be obtained in respect of such costs. In that event, the company may not be able to claim tax refunds for all of its exploration costs.

FINANCIAL RISKS

- **The company may require additional capital, which may not be available on favorable terms**

The company's future capital requirements depend on many factors, including whether the company's cash flow from operations is sufficient to fund the company's business plans. The company may need additional funds in the longer term in order to further develop exploration and development programs or to acquire assets or shares of other companies. In particular, the development projects require significant capital expenditures in the years to come. Even though the company has taken measures to ensure a solid financial basis for the development projects, the company cannot assure that it will be able to generate or obtain sufficient funds to finance the projects. In particular, given the extensive scope of the projects, any unforeseen circumstances or actions to be dealt with that are not accounted for, may result in a substantial gap between estimated and actual costs. Thus, the actual costs necessary to carry out the projects may be considerably higher than currently estimated. These investments, along with the company's ongoing operations, may be financed partially or wholly with debt, which may increase the company's debt levels above industry standards.

The company may also have to manage its business in a certain way so as to service its debt and other financial obligations. Should the financing of the company not be sufficient to meet its financing needs, the company may, among other things, be forced to reduce or delay capital expenditures or research and development expenditures or sell assets or businesses at unanticipated times and/or at unfavorable prices or other terms, or to seek additional equity capital or to restructure or refinance its debt. There can be no assurance that such measures would be successful or would be adequate to meet debt and other obligations as they come due, or would not result in the company being placed in a less competitive position.

The general financial market conditions, stock exchange climate, interest level, the investors' interest in the company, the share price of the company, as well as a number of other factors beyond the company's control, may restrict the company's ability to raise necessary funds for future growth and/or investments. Thus, additional funding may not be available to the company or, if available, may not be available on acceptable terms. If the company is unable to raise additional funds as needed, the scope of its operations may be reduced and, as a result, the company may be unable to fulfil its long-term development program, or meet its obligations under its contracts, which may ultimately be withdrawn or terminated for non-compliance. The company may also have to forfeit or forego various opportunities, curtail its growth and/or reduce its assets. This could have a material adverse effect on the company's business, prospects, financial condition, results of operations and cash flows, and on the company's ability to fund the development of its business.

- **The company is exposed to interest rate and liquidity risk associated with its borrowing portfolio and fluctuations in underlying interest rates**

The company's long-term debt is primarily based on floating interest rates. An increase in interest rates can therefore materially adversely affect the company's cash flows, operating results and financial condition and make it difficult to service its financial obligations. The company has, and will in the future have, covenants related to its financial commitments. Failure to comply with financial obligations, financial covenants and other covenants may entail several material adverse consequences, including the need to refinance, restructure, or dispose of certain parts of, the company's businesses in order to fulfil the company's financial obligations and there can be no assurances that the company in such event will be able to fulfil its financial obligations.

- **Changes in foreign exchange rates may affect the company's results of operations and financial position**

The company is exposed to market fluctuations in foreign exchange rates due to the fact that the company reports profit and loss and the balance sheet in USD. Revenues are in USD for oil and in GBP and EUR for gas, while operational costs and investments are in several other currencies in addition to USD. Moreover, taxes are calculated and paid in NOK. The company actively manages its foreign currency exposure through a mix of forward contracts and options, however significant fluctuations in exchange rates between USD and NOK could adversely affect the liquidity position of the company. The company expects to maintain its foreign exchange hedging activity in 2018.

- **The company is exposed to risk of counterparties being unable to fulfil their financial obligations**

The company's partners and counterparties consist of a diverse group of companies with no single material source of credit risk. However, a general downturn in financial markets and economic activity may result in a higher volume of late payments and outstanding receivables, which may in turn adversely affect the company's business, operating results, cash flows and financial condition.

Events after the year-end closing of the accounts

On 15 January 2019, Aker BP was offered 21 new licenses, including 11 operatorships in the Awards in Predefined Areas (APA) 2018 licensing round.

On 17 January 2019, Aker BP announced that the company would reorganize its finance functions. David Tønne was appointed CFO, while Lene Landøy was appointed director with responsibility for Strategy and Business Development. Both are part of the company's executive management team. Alexander Krane moved to a position as investment director at Aker ASA.

On 4 February 2019, Aker BP announced a discovery of oil and gas at Froskelår in licence 869 in the Alvheim area. Aker BP is the operator and holds 60 % interest in the licence.

On 19 February 2019, Aker BP disbursed USD 187.5 million in dividends to shareholders.

BOARD OF DIRECTORS' – signature page

The Board of Directors of Aker BP ASA
Akerkvartalet, 13 March 2019

Øyvind Eriksen
ØYVIND ERIKSEN
Chairman

Anne Marie Cannon
ANNE MARIE CANNON
Deputy chair

KJELL INGE RØKKE
Board member

Trond Brandsrud
TROND BRANDSRUD
Board member

GRO KIELLAND
Board member

BERNARD LOONEY
Board member

KATE THOMSON
Board member

INGARD HAUGEBERG
Board member

Anette Helg
ANETTE HOEL HELGESEN
Board member

ØRJAN HOLSTAD
Board member

TERJE SOLHEIM
Board member

KARL JOHNNY HERSVIK
Chief Executive Officer

REPORTING OF PAYMENTS TO GOVERNMENTS

This report is prepared in accordance with Section 3-3 d) of the Norwegian Accounting Act and Section 5-5 a) of the Securities Trading Act, which require companies engaged in activities within the extractive industries to prepare and publish a report containing information about their payments to governments at country and project level every year. The Ministry of Finance has issued a regulation (F20.12.2013 nr 1682 – «the regulation») stipulating that the reporting obligation only applies to reporting entities above a certain size and to payments above certain threshold amounts. In addition, the regulation stipulates that the report shall include other information than payments to governments, and it provides more detailed rules applicable to definitions, publication and group reporting.

The management of Aker BP has applied judgment in interpreting the wording in the regulation with regard to the specific type of payment to be included in this report, and on what level it should be reported. When payments are required to be reported on a project-by-project basis, it is reported on a field-by-field basis. Only gross amounts are reported for operated licences, as all payments made within the licence by non-operators will normally be cash calls transferred to the operator, and they will therefore not be payments to the government.

REPORTING OF PAYMENTS

Section 2 no. 5 of the regulation defines the different types of payments subject to reporting. In the following sections, only those applicable to Aker BP will be described.

Income tax

The income tax is calculated and paid at corporate level and is therefore reported for the whole company rather than licence-by-licence. The tax payments in 2018 of NOK 4,959,868,897 (including interest) are mainly related to tax instalments for the income year 2017 and income year 2018. This figure excludes tax refunds received in 2018.

CO_2 tax

CO_2 tax is to some extent included in the fuel price/rig rental paid to external rig companies. The CO_2 tax paid on the Alvheim field includes the fields tied in to the Alvheim FPSO (Vilje, Volund and Bøyla), as Alvheim performs the payment and charges the other fields via opex share.

Name of field/licence	CO_2 tax paid in 2018 (NOK)
Alvheim	96 682 189
Ivar Aasen	19 227 200
Hod	197 634
Valhall	4 579 097
Ula	72 257 288
Skarv	177 330 492
Tambar	1 794 727
Total CO_2 paid	**372 068 628**

NOx

The company is a member of the NOx fund and all NOx payments are made to this fund rather than to the government.

Area fee

The table below specifies the area fee paid by Aker BP on behalf of the different licences in 2018. Licenses for which the company has received a net refund of the area fee are not included in the figures.

Name of field/licence	Area fee paid in 2018 (NOK)
Alvheim	14 757 891
Bøyla	4 590 000
Hod	2 695 000
Skarv	32 283 000
Tambar	4 590 000
Ula	4 949 000
Valhall	6 272 000
Vilje	931 000
Volund	765 000
PL 019C	1 519 000
PL 019E	877 315
PL 026B	834 738
PL 027D	1 377 000
PL 033B	2 352 000
PL 065B	883 480
PL 159D	1 071 000
PL 169C	1 377 000
PL 212B	3 519 000
PL 212E	6 426 000
PL 242	2 448 000
PL 261	10 404 000
PL 364	80 482
PL 442	11 355 000
PL 460	8 035 644
PL 504	1 071 000
PL 626	6 960 975
Total CO_2 paid	**132 424 525**

OTHER INFORMATION THAT MUST BE REPORTED

When companies are required to report payments as the above, it is also mandatory to report on investments, sales income, production volumes and purchases of goods and services in the country where the companies have activities within the extractive industries. As mentioned above, Aker BP operates on the Norwegian Continental Shelf only. This reporting requirement is therefore deemed to be met by the financial statements as specified below:

- Total net investments amounted to USD 2,147,086 thousand, as specified in the cash flow analysis in the financial statements.
- Sales income (Petroleum revenues) in 2018 amounted to USD 3,711,472 thousand, as specified in Note 6 to the financial statements
- Total production in 2018 was 56,815,246 barrels of oil equivalents, see Note 6 to the financial statements
- For information about purchases of goods and services, reference is made to the Income Statement and the related notes

THE BOARD OF DIRECTORS' REPORT ON CORPORATE GOVERNANCE

Aker BP ASA («Aker BP») aims to ensure the greatest possible value creation to shareholders and society over time in a safe and prudent manner. A good management and control model with a clear division of responsibility and roles between the owners, represented by the shareholders in the General Meeting, the Board of Directors and corporate management is crucial to achieve this.

1. Implementation and reporting on corporate governance

The Board of Aker BP is responsible for actively adhering to sound corporate governance standards.

Aker BP is a Norwegian public limited liability company (ASA), listed on the Oslo Stock Exchange and established under Norwegian laws. In accordance with the Norwegian Accounting Act, section 3-3b, Aker BP includes a description of principles for corporate governance as part of the Board of Directors' Report in the annual report or alternatively makes a reference to where this information can be found.

The Norwegian Corporate Governance Board («NCGB») has issued the Norwegian Code of Practice for Corporate Governance («the Code»). The Code can be found on www.nues.no. Adherence to the Code is based on the «comply or explain» principle, which means that a company must comply with all the recommendations of the Code or explain why it has chosen an alternative approach to specific recommendations.

The Oslo Stock Exchange requires listed companies to publish an annual statement of their policy on corporate governance in accordance with the Code in force at the time. Continuing obligations for companies listed on the Oslo Stock Exchange is available at www.oslobors.no.

Aker BP complies with all applicable laws and regulations. Aker BP complies with the current edition of the Code, issued on 17 October 2018, unless otherwise specifically stated. The following statement on corporate governance is structured in the same way as the Code, thus following the 15 chapters included in the Code.

Deviations from the code: None

2. Business

According to Aker BP's Articles of Association article 3, its objective is «to carry out exploration for, and recovery of, petroleum and activities related thereto, and, by subscribing for shares or by other means, to participate in corresponding businesses or other business, alone or in cooperation with other enterprises and interests». Further information about the Articles of Association is available at: http://www.akerbp.com/en/investor/corporate-governance/articles-of-association/.

Through an annual strategy process, the Board defines and evaluates the company's goals, main strategies and risk profiles for the company's business activities such that the company creates value for shareholders. Together with the company's financial status, these goals are communicated to the market.

It is Aker BP's objective to create the leading independent offshore E&P company. In order to achieve this objective, the company will take part in exploration, development and production activities and be opportunistic in its approach to M&A, including buying and selling interests in companies, fields and discoveries.

The company has adopted a Code of Conduct to ensure that employees, hired personnel, consultants and others acting on behalf of Aker BP, do so in a consistent manner with respect to ethics and good business practice. The Code of Conduct clarifies the company's fundamental ethical values including corporate social responsibility and is a guideline for those making decisions on behalf of the company. The Code of Conduct is available on the website http://www.akerbp.com/en/about-us/code-of-conduct/.

The company shall demonstrate responsibility through actions, the quality of its work, the projects and products and all its activities. The company's ambition is that business activities shall integrate social, ethical and environmental goals and measures. As a minimum, Aker BP will comply with laws, regulations and conventions in the areas where the company operates, but the established set of ethical guidelines extends beyond such compliance. Established procurement procedures secure non-discrimination and transparency in the procurement processes. It is also stated in the Code of Conduct that any form of corruption is not tolerated. Aker BP's Anti-Corruption Policy sets out in more detail the company's expectations to the actions of Aker BP Representatives and Business Partners, and is available on the website https://www.akerbp.com/en/about-us/code-of-conduct/aker-bp-anti-corruption-policy/.

In addition, the company has a sponsorship programme to promote the company and its activities. Guidelines for the use of sponsorships are included in the Code of Conduct. Aker BP supports measures that are directly related to the company's business as an oil company, measures that improve the company's profile and measures that can be for the benefit of the employees. Information about ongoing sponsorships are available on the website: http://www.akerbp.com/en/about-us/csr/sponsorships/.

The company integrates considerations related to its stakeholders into its value creation and shall achieve its goals in accordance with the Code of Conduct.

Deviations from the code: None

3. Equity and dividends

The Board seeks to optimize the company's capital structure by balancing risk, return on equity against lenders' security and liquidity requirements. The company aims to have a good reputation in all debt and equity markets. The Board continuously evaluates the company's capital structure, ensuring a capital and debt structure that is appropriate to the company's objective, strategy and risk profile. This involves monitoring available funding sources and related cost of capital.

At year-end 2018, the company's book equity was USD 2.99 billion, which represents 28 per cent of the balance sheet total of USD 10.78 billion. The market value of the company's equity was USD 9.04 billion (NOK 78.50 billion) on 31 December 2018.

It is the company's goal that over time, Aker BP's shareholders shall receive a competitive return on their investment through increased share price and cash dividends. The Annual General Meeting («AGM») in April 2018 authorized the Board to approve the distribution of dividends on the basis of the approved annual accounts for 2017. The background of this proposal was to facilitate the company's aim to distribute dividends quarterly. In 2018, the company paid USD 450 million (USD 1.2496 per share) in dividends to shareholders. For 2019, the company plans to pay USD 750 million in dividends, and the ambition is to increase this by USD 100 million per year until 2023.

The company's financial liquidity is considered to be good. At 31 December 2018, the company's cash and cash equivalents were USD 45 million. In addition, available undrawn amounts on committed credit facilities were USD 3.05 billion.

In April 2018, the AGM authorized the Board to increase the share capital by a maximum of NOK 18,005,675, representing up to five per cent of the total share capital at the time of such meeting. The authorization can be utilized for share capital increases in order to strengthen the company's equity, convert debt into equity and fund business opportunities. At 31 December 2018, the mandate had not been used.

The AGM in April 2018 also provided the Board with a mandate to acquire company shares equivalent to up to five per cent of the total share capital at the time of such meeting. The purpose for this mandate was; i) utilization as transaction currency in connection with acquisitions, mergers, demergers or other transactions, ii) of investment or for subsequent sale or cancellation of such shares and iii) in connection with the share savings plan for employees. The mandate is valid until the AGM in 2019. At 31 December 2018, the mandate had only been used in connection with the share savings plan for employees. The company's employees subscribed for a total of 465,335 shares. After delivery of these shares, Aker BP held zero treasury shares.

Deviations from the code: None

4. Equal treatment of shareholders and transactions with close associates

The company has one class of shares and all shares carry the same rights.

When the company considers it to be in the best interest of shareholders to issue new equity there is a clear objective to limit the level of dilution. Aker BP will carefully consider alternative financing options, its overall capital structure, the purpose and need for new equity, the timing of such an offering, the offer share price, the financial market conditions and the need for compensating existing shareholders in the event that pre-emption rights are waived. Arguments for waiving pre-emption rights will be clearly stated.

In the event that the Board decides to use its current authorization to re-purchase company shares, the transactions will be carried out through the stock exchange or at prevailing stock exchange prices if carried out in any other way.

At 31 December 2018, Aker Capital AS owned 40.0 per cent of Aker BP. Aker Capital AS is a wholly-owned subsidiary of Aker ASA. Following the merger with BP Norge AS in 2016, Aker ASA de-consolidated Aker BP and started to account for Aker BP in accordance with the equity method.

Aker BP is committed to equal treatment of all shareholders. The Board is of the view that it is positive for Aker BP that Aker ASA and BP P.L.C. assume the role of active owners and are actively involved in matters of major importance to Aker BP and to all shareholders. The cooperation with Aker ASA and BP P.L.C. offers Aker BP access to expertise and resources within upstream business activities, technology, strategy, transactions and funding. It may be necessary to offer Aker ASA and BP P.L.C. special access to commercial information in connection with such cooperation. Any information disclosed to Aker ASA's and BP P.L.C.'s representatives in such a context will be disclosed in compliance with the laws and regulations governing the stock exchange and the securities market.

Applicable accounting standards and regulations require Aker ASA and BP P.L.C. to prepare their consolidated financial statements to include accounting information of Aker BP. Aker BP is considered an associate of Aker ASA and BP P.L.C. under the applicable accounting standard. In order to comply with these accounting standards, Aker ASA and BP P.L.C. have in the past received, and will going forward receive, unpublished accounting information from Aker BP. Such distribution of unpublished accounting information from Aker BP to Aker ASA and BP P.L.C. is executed under strict confidentiality and in accordance with applicable regulations on the handling of inside information.

The Board recognizes Aker ASA's and BP P.L.C.'s contribution as active shareholders. Investor communication seeks to ensure that any shareholders are able to contribute, and management will actively meet with and seek the views of shareholders. Investor activities are also directed at promoting higher stock liquidity to balance a shareholder structure with many long-term investors.

Aker BP has no related parties, as defined in the Public Limited Liability Company Act («Almennaksjeloven»). The company has nevertheless established procedures for transactions with such parties and also extended these to include Aker ASA. The Board of Directors and executive management are nevertheless very conscious that all relations with Aker ASA and BP P.L.C., its subsidiaries and other companies in which Aker ASA or BP P.L.C. have ownership interests or entities they have significant control over, shall be premised on commercial terms and are entered into on an arm's-length basis. Transactions with Aker and BP controlled companies are described in the financial statements' disclosure about transactions with related parties.

Deviations from the code: None

5. Shares and negotiability

Aker BP's shares are freely negotiable securities and the company's Articles of Association do not impose any form of restriction on their negotiability.

The company's shares are listed on the Oslo Stock Exchange and the company works actively to attract the interest of new Norwegian and foreign shareholders. Strong liquidity in the company's shares is essential if the company is to be viewed as an attractive investment and thus achieve a low cost of capital.

Deviations from the code: None

6. General meetings

The General Meeting of shareholders is the company's highest authority. The Board strives to ensure that the General Meeting is an effective forum for communication between the shareholders and the Board, and encourages shareholders to participate in the meetings.

The Board can convene an extraordinary General Meeting at any time. A shareholder or a group holding at least five per cent of the company's shares can request an extraordinary General Meeting. The Board is then obliged to hold the meeting within one month of receiving the request.

Preparation for General Meetings

The AGM is normally held before the end of April each year, and no later than the end of June, which is the latest date permitted by the Public Limited Liability Companies Act. The date of the next AGM is normally included in the company's financial calendar, which is available at https://www.akerbp.com/investor/finansiell-kalender/.

The notice of a General Meeting is sent to shareholders, and published on the company's website and the stock exchange, no later than 21 days prior to the meeting.

Article 7 of the company's Articles of Association, about the General Meeting, stipulates that documents concerning matters to be considered by the General Meeting will be made available to the shareholders on the company's website. This also applies to documents that are required by law to be included in or enclosed with the notice of the General Meeting.

The supporting documentation provides the necessary information for shareholders to form a view on the matters to be considered.

Participation in a General Meeting

The Board ensures that the company's shareholders can participate in the general meeting. According to Article 7 in the Articles of Association, the right to attend and vote at the General Meeting can only be exercised when the share transaction is recorded in the shareholder register no later than the fifth business day prior to the General Meeting (registration date).

Shareholders who are unable to attend a General Meeting are encouraged to vote by proxy. A form for the appointment of a proxy, which allows separate voting instructions to be given for each matter to be considered by the meeting, is included with the notice. The deadline for registration is set as close as possible to the date of the meeting, normally the day before.

Conduct of a General Meeting and agenda for AGM

The Board proposes the agenda for the AGM. The main agenda items are determined by the requirements of the Public Limited Liability Companies Act and Article 7 in the company's Articles of Association.

Before the AGM, the Board will nominate a person who can vote on behalf of shareholders as their authorized representative. Shareholders may cast their votes in writing, including by means of electronic communication, in a given period prior to the General Meeting. Appropriate arrangements are made for shareholders to vote separately on candidates nominated for election to the company's corporate bodies.

Aker BP's General Meetings are normally chaired by the Chairman of the Board, or a person appointed by the Chairman of the Board. If there is reason to perceive the Chairman of the Board as being personally conflicted in respect of any matters then another person will be appointed to chair the meeting.

The Code states that it is appropriate that all members of the Board should attend General Meetings. Representatives from the Board, the nomination committee, the auditor and the executive management will attend the AGM.

Minutes of General Meetings are published on the company's website and through a stock exchange announcement.

Deviations from the code: The code recommends that all members of the Board are present at the General Meeting and that the chairman of the Nomination Committee should attend the AGM. Due to the nature of discussions at General Meetings, Aker BP has not deemed it necessary to require all Board members and the chairman of the Nomination Committee to be present.

7. Nomination committee

Article 8 in the company's Articles of Association stipulates that the Nomination Committee shall consist of three members elected by the General Meeting. It also stipulates that the majority of the members shall be independent of the Board and the executive management and that the members shall be elected for a period of two years at a time. The committee's remuneration is determined by the General Meeting.

At the AGM in April 2018, Finn Haugan and Hilde Myrberg were re-elected as members of the Nomination Committee for two years. Arild Støren Frick was re-elected as the Chair of the Nomination Committee for two years in 2017. No members of the committee are members of executive management or the Board of Aker BP.

The Nomination Committee should be composed in such a way that it represents a wide range of shareholders' interests. It should also be strived for both genders being represented in the committee. The Nomination Committee's duties are also stated in Article 8 in the Articles of Association. The committee shall propose candidates for - and remuneration to - the Board of Directors and the Nomination Committee and justify its recommendation for each candidate separately.

Shareholders have an opportunity to submit proposals to the committee. The electronic mailbox for submitting proposals to the committee, with deadlines for submitting proposals where such apply, is accessible through the company's website at www.akerbp.com/proposecandidate/.

Deviations from the code: None

8. Board of Directors: Composition and independence

The Board of Aker BP consisted of eleven members at 31 December 2018. The company's Articles of Associations Article 5, stipulates that the Board shall consist of up to eleven members.

The general meeting elects the Chairman of the Board. The term of office for members of the Board is two years at a time.

Among the shareholder-elected Board members, two (Kjell Inge Røkke and Øyvind Eriksen) are affiliated with the company's largest shareholder Aker ASA. Deputy Chair Anne Marie Cannon is a member of the Board of Directors for Aker ASA. Among the shareholder-elected Board members, two (Bernard Looney and Kate Thomson) are affiliated with the company's second largest shareholder BP P.L.C.. All other Board members are considered independent of the company's two main shareholders, as well as of the company's material business contacts. All Board members are considered independent of the company's executive personnel.

In 2018, the Board conducted a total of 9 Board meetings. Participation was 92 percent.

The Board composition ensures alignment of interests with all shareholders and members of the Board are encouraged to own shares in the company. It is the Board's view that the Board collectively meets the need for expertise, capacity and diversity. Board members possess strong experience from banking and finance, oil and gas sector in general, and reservoir engineering, exploration and field development in particular.

An overview of the expertise of the Board members is available on the website: www.akerbp.com/en/about-us/board-of-directors/.

Deviations from the code: None

9. The work of the board of directors

The Board has authority over and is responsible for supervising the company's business operations and management and has adopted a yearly plan for its activities. The Board handles matters of major importance, or of an extraordinary nature and may in addition require management to refer any matter to it. The objectives of the Board's work are to create value for the company's shareholders in both the short and long term and to ensure that Aker BP fulfils its obligations at all times. An important task for the Board is to appoint the CEO and while the CEO is responsible for the day-to-day management of the company's business activities, the Board acknowledges its responsibility for the overall management of the company. The Board is responsible for:

A. Drawing up strategic plans and supervising these through regular reporting and reviewing,
B. Identifying significant risks to Aker BP's activities and establishing appropriate systems to monitor and manage such risks,
C. Ensuring that shareholders have access to timely and correct information about financial circumstances and important business-related events in accordance with relevant legislation, and
D. Ensuring the establishment and securing the integrity of the company's internal control and management systems.

The Board recognizes the significant risks associated with operations. Consequently, the Board has dedicated significant resources and time to understand and discuss not only general risks facing an E&P company, but also inherent risks connected to organization, culture and leadership. For a company like Aker BP, the Board views the risks in taking on an operated development project and meeting the required financing for its entire portfolio as well as taking on operated assets, to be among the most significant risks. Accordingly, this is where the mitigating efforts are concentrated.

The work of the Board is based on the rules of procedure describing the Board's responsibility including the division of roles between the Board and the CEO. There are specific instructions to guide the work of the CEO. The CEO, CFO and the company secretary attend all Board meetings. Other members of the company's executive management attend the Board meetings by invitation and as necessary due to specific matters. If the Chair of the Board has been personally involved in matters of a material character, the Deputy Chair takes over the tasks of the chair directing the Board's work in the specific matter.

Considering the size of the company and the scope of its activities, the Board finds it appropriate to keep all Board members informed about all Board matters, except for cases where Board members may have conflicting interests with the company. The Board carried out a self-evaluation of its own performance for 2018 which included an evaluation of the Board's competence and potential areas for strengthening this competence.

The Board ensures that members of the board of directors and executive personnel make the company aware of any material interests that they may have in items to be considered by the board of directors. The company's Code of Conduct provides clear guidelines as to how employees and representatives of the company's governing bodies should act in situations where there is a risk of conflicts of interest and partiality.

Audit and Risk Committee

The Board has established an Audit and Risk Committee consisting of the following Board members:

- Trond Brandsrud, Chair
- Anne Marie Cannon
- Kate Thomson

All members are independent of the company's executive management. Anne Marie Cannon sits on the Board of Directors in Aker ASA, the largest shareholder in Aker BP. Cannon also sits on the Board of Directors in Aker Energy AS, which is 50% owned by Aker ASA. Kate Thomson is Group Treasurer with BP P.L.C.

The Chair of the Audit and Risk Committee is considered to have experience and formal background qualifying as «financial expert» according to the requirement stated in the Public Limited Liability Company Act. In the period 2016-2017 Trond Brandsrud was Chief Financial Officer at Lindorff. From 2010 to 2015, he was the Chief Financial Officer of Aker ASA. He has also been Chief Financial Officer in Seadrill, and he has held several leading financial positions in Shell for 20 years, both in Norway and globally.

The Audit and Risk Committee holds regular meetings and reviews the quality of all interim and annual reports before they are reviewed by the Board of Directors and then published. In 2018, the committee held 7 meetings.

The company's auditor works closely with the Audit and Risk Committee and attended all meetings during the year. The committee also oversees the company's financial risk management and monitors and reviews the company's business risk. The management and the Audit and Risk Committee evaluate the risk management on financial reporting and the effectiveness of established internal controls. Identified risks and effects of financial reporting are discussed on a quarterly basis.

Oversight of HSSE and operational risks is retained directly by the Board. The Board has established a committee to strengthen the administration work on HSSE which reports to the Board on a quarterly basis.

It is the view of the committee that cooperation between the auditor and executive management is good. The Audit and Risk Committee has worked together with executive management and the auditor to improve the internal control environment according to the COSO (Committee of Sponsoring Organizations of the Treadway Commission) framework over the last 3 years.

Compensation and Organizational Development Committee

The Board has a Compensation and Organizational Development Committee consisting of the following three Board members:

- Øyvind Eriksen, Chair
- Gro Kielland
- Terje Solheim

The Compensation and Organizational Development Committee is established to ensure that remuneration arrangements support the strategy of the business and enable the recruitment, succession planning and leadership development, and motivation and retention of senior executives. It needs to comply with the requirements of regulatory and governance bodies, satisfy the expectations of shareholders and remain consistent with the expectations of the wider employee population. Further, the committee shall ensure that the overall organizational structure is set up to deliver on the company's strategy going forward. In 2018, the committee held 4 meetings.

In addition to the Audit and Risk Committee and Compensation and Organizational Development Committee, the Board may appoint various ad hoc sub-committees when required, with a limited timeframe and scope. The authority of a sub-committee is limited to preparing items and making recommendations to the Board.

Deviations from the code: None

10. RISK MANAGEMENT AND INTERNAL CONTROL

Risk Management

Appropriate internal control and risk management contributes to the transparency and quality reporting for the benefit of the company, stakeholders, shareholders' long-term interests and the operational challenges as an operator on the Norwegian Continental Shelf.

The company continuously and systematically operates a robust and transparent risk management process vertically and horizontally throughout the organisation.

The company's operational activities are limited to Norway and are subject to Norwegian regulations. All activities taking place in a production license are subject to supervision and audits from governmental bodies (e.g. the Petroleum Safety Authority Norway (Norwegian PSA) and the Norwegian Environment Agency), and license partners.

The Board considers risk in the context of growing a sustainable business while meeting governance, safety and accountability expected by stakeholders. The Board and the Audit and Risk Committee regularly review major risks identified and reported through the company Enterprise Risk Management process.

The Business Management System (BMS) is formed by a cultural framework and a structural framework and encompasses the company's guidelines for how it integrates considerations related to stakeholders into its creation of value (Code of Conduct). The structural framework consists of twelve common governing models, the asset value chain and a set of technical support and business support process areas. The purpose of the process is to enable the company to maximise opportunities, minimise threats and optimise achievements of business objectives. Risk is addressed and managed across silos throughout the asset value chain. One common way of working supported by a common infrastructure enables holistic risk management at all levels.

The company's risk response includes monitoring of enduring and emerging risks through continuous analysis and engagement with operational management. The company may consult external advisors to find the most appropriate and balanced risk response.

Internal control for financial reporting

Aker BP has established a framework for Internal Control for Financial Reporting based on COSO (Committee of Sponsoring Organizations of the Treadway Commission) and is operationalized as follows:

- Internal Control Environment
- Objective setting
- Event Identification and Risk Assessment
- Risk Response and Control Activities
- Information and communication
- Monitoring

The established framework is an integrated part of the company's management system. The company's internal control environment is characterized by clearly defined responsibilities and roles between the Board of Directors, Audit and Risk committee and management. The implemented procedure for financial reporting is integrated with the company's management system, including ethical guidelines that describe how the representatives of the company must act.

The company has established processes, procedures and controls for financial reporting, which are appropriate for an exploration and production company. The company's documented procedures enable:

- Effective and appropriate identification of risks
- Measurement of compliance against procedures

- Sufficient segregation of duties
- Provision of relevant, timely and reliable financial reporting that provides a fair view of Aker BP's business
- Prevention of manipulation/fraud of reported figures
- Compliance with all relevant requirements of IFRS

A risk assessment related to financial reporting is performed and documented by management. Risk assessments are monitored by the Audit and Risk Committee on a quarterly basis as part of the quarterly reporting process. The Board of Directors approves the overall risk assessment related to financial reporting on an annual basis. In 2018, the following main risk areas were identified related to financial reporting:

- Impairment of goodwill, tangible and intangible assets – There is a risk that fair value declines are not identified and recorded in an appropriate manner
- Tax – Complexity in tax regulations and calculation entail risk of error in financial reporting
- Transformation to become an even larger exploration and production company – There is a risk that the company does not have adequate procedures and systems for financial and reserves reporting
- Asset retirement obligation - There is a risk of errors in the estimates and calculations during the ARO process

The company seeks to communicate transparently on its activities and its financial reporting which is made after significant interaction with management responsible for exploration, development and production activities in the business.

Key events that may affect the financial reporting are identified and monitored continuously. An «Issue list» is established to address possible accounting and tax effects of events and activities. Both the auditor and the Audit and Risk committee review the «Issue list» at least on a quarterly basis.

The Finance Department monitors the compliance with established procedures and reports any material deviations to the Audit and Risk Committee. It also identifies actions to improve procedures and conducts a self-assessment of its performance against objectives, which are then presented and discussed with the Audit and Risk Committee. A new accounting system that fully integrates the previous BP Norge AS in this system went live in January 2018.

In 2019, Aker BP will continue to focus on improvements of internal controls and further develop the new accounting system. The internal control environment has been evaluated and will be strengthened as part of the new SAP solution for Aker BP.

Deviations from the code: None

11. Remuneration of the board of directors

The remuneration of the Board members is not performance-based, but based on a fixed annual fee. None of the shareholder-elected Board members have pension schemes or termination payment agreements with the company. The company does not grant share options to members of the Board. Information about all remuneration paid to individual Board members is provided in Note 9 to the annual accounts.

The General Meeting decides the remuneration of the Board and the sub-committees. The Nomination Committee proposes the remuneration of the Board to the General Meeting and ensures that it reflects the responsibility of its members and the time spent on Board work. The Board must approve any Board member's consultancy work for the company and remuneration for such work. No such work was carried out during 2018.

Deviations from the code: None

12. Remuneration of executive personnel

The Board makes guidelines for executive remuneration, including the CEO's remuneration and other terms and conditions of employment. These guidelines set out the main principles applied in determining the salary and other remuneration of executive personnel and are communicated to the annual general meeting. Note 9 to the annual accounts contains details about the remuneration of the Board and Executive Management Team («EMT»), including payroll, bonus payments and pension expenses.

Members of EMT have individual maximum bonus potential varying from 60 per cent to 100 per cent of their base salary. The maximum bonus for employees outside the EMT varies from 10 per cent to 30 per cent based on internal job grade.

The bonus for all employees, including the EMT, is determined by the performance on a set of company-wide performance indicators (KPIs) and the delivery on a set of carefully selected company Priorities. The set of KPIs and Priorities each weigh 50 per cent. KPI's include measures on Safety, Production, Production Cost, Reserve additions, Value creation and Shareholder Return. Company Priorities are either important improvement initiatives or activities with clear deliverables that are critical for the company's future success.

In addition, certain members of the EMT participated in a one-off, three-year incentive program started in January 2015, through December 2017, linked to the relative performance of the Aker BP share price versus a benchmark index consisting of the average of the Oslo Stock Exchange Energy Index and the Stoxx 600 Europe Oil & Gas index. Total payment in 2017 was capped at 60 per cent of the executive manager's annual base salary or a monetary amount.

The CEO incentive program started in 2014, through December 2018, and was capped at NOK 15 million. A new incentive program is currently being assessed, but not yet finalized.

The pension scheme continued to be a defined contribution plan capped at twelve times the National Insurance scheme basic amount (12G) for all employees including the executive management.

Deviations from the code: None

13. Information and communications

Aker BP maintains a proactive dialogue with analysts, investors and other stakeholders of the company. The company strives to continuously publish relevant information to the market in a timely, effective and non-discriminatory manner, and has a clear goal to attract both Norwegian and foreign investors and to promote higher stock liquidity.

All stock exchange announcements are made available on the Oslo Stock Exchange website, www.newsweb.no, as well as the company's website (www.akerbp.com) at the same time. The announcements are also distributed to news agencies and other online services.

Aker BP publishes its preliminary annual accounts by the end of February, as part of its fourth quarter report. The complete annual report, including approved and audited accounts and the Board of Directors' Report, is available no later than three weeks before the AGM. Information sent to shareholders is published on the website simultaneously.

The company's financial calendar for the coming year is published as a stock exchange announcement and made available on the company's website no later than 31 December each year, in accordance with the continuing obligations for companies listed on the Oslo Stock Exchange.

Aker BP holds open presentations in connection with the publication of the company's quarterly results in addition to an annual capital markets day. The presentations are webcasted for the benefit of investors who are prevented from attending or do not wish to attend the presentations. At the presentations, executive management review and comment on the published results, market conditions and the company's future activities.

The company's management gives high priority to communication with the investor market. Individual meetings are organized for a wide range of existing and potential new investors and analysts. The company also attends relevant industry and investor conferences.

Aker BP will reduce its contacts with analysts, investors and journalists in the final two weeks before publication of its results. During this period, the company will give no comments to the media or other parties about the company's results and future outlook. This is to ensure that all interested parties in the market are treated equally.

Deviations from the code: None

14. Take-overs

The Board has established a separate set of guidelines for how it will act in the event of a takeover bid, as recommended by the Code. The overriding principle for review of a takeover bid is equal treatment of shareholders. The principles are based on the Board of Directors and management having an independent responsibility for fair and equal treatment of shareholders in a takeover process, and that the day-to-day operations of the company are not unnecessarily disturbed. It is management's responsibility to ensure that the Board of Directors is made aware of any potential takeover bid, while the Board of Directors is responsible for ensuring that shareholders are kept informed and are given reasonable time to consider the offer.

Unless the Board of Directors has particular reason, it will not take steps to prevent or obstruct a takeover bid for the company's shares, nor hinder the progress of the bid without approval from shareholders.

If an offer is made for Aker BP's shares, the Board of Directors should make a statement to the shareholders that contains an assessment of the bid, the Board of Directors' recommendations and the reason for the recommendation. If the Board of Directors is unable to make a recommendation to shareholders, the Board of Directors shall explain its reasoning for this.

Transactions that have the effect of a sale of the company or a major part of it must be decided on by shareholders at a shareholders' meeting.

Deviations from the code: None

15. Auditor

The AGM elects the auditor and approves the auditor's fee. The Board of Directors will meet with the auditor annually without representatives of company management being present, to review internal control procedures and discuss any weaknesses and proposals for improvement. The auditor is invited and participates in the Board meetings to discuss the annual accounts. In these meetings, the auditor reports on any material changes in the company's accounting principles and key aspects of the audit, including matters on which there has been disagreement between the auditor and the executive management of the company.

The auditor participates in all meetings with the Audit and Risk Committee and meets the Audit and Risk Committee without the company's management being present. The Board ensures that the auditor submits the main features of the plan for the annual audit of the company to the Audit and Risk Committee annually. The auditor's independence in relation to the company is evaluated annually. The auditor may carry out certain audit related or non-audit services for the company, providing these are not in conflict with its duties as auditor. The company has established an audit and non-audit service policy.

In the annual financial statements, the auditor's remuneration is split between the audit fee and fees for other services. In the presentation to the AGM, the chair presents a breakdown between the audit fee and fees for other services.

Deviations from the code: None

FINANCIAL STATEMENTS

FINANCIAL STATEMENTS WITH NOTES

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INCOME STATEMENT

(USD 1 000)	Note	Group 2018	Group 2017	Parent 2018	Parent 2017
Petroleum revenues	6	3 711 472	2 575 654	3 711 472	2 575 654
Other operating income	6	38 600	-12 721	38 600	-12 721
Total income		3 750 072	2 562 933	3 750 072	2 562 933
Production costs		689 102	523 379	689 102	523 379
Exploration expenses	4	295 908	225 702	295 908	225 702
Depreciation	12	752 437	726 670	752 437	726 670
Impairments	12, 13	20 172	52 349	20 172	52 349
Other operating expenses	7,8	17 037	27 606	17 037	27 582
Total operating expenses		1 774 658	1 555 705	1 774 658	1 555 682
Operating profit		1 975 414	1 007 228	1 975 414	1 007 252
Interest income		25 976	7 716	19 114	7 012
Other financial income		141 823	75 507	185 415	116 401
Interest expenses		120 033	103 627	120 033	123 171
Other financial expenses		218 272	175 696	281 689	176 052
Net financial items	9	-170 505	-196 100	-197 192	-175 810
Profit before taxes		1 804 909	811 128	1 778 222	831 441
Taxes (+)/tax income (-)	10	1 328 486	536 340	1 326 907	531 487
Net profit		476 423	274 787	451 315	299 955
Weighted average no. of shares outstanding basic and diluted	11	360 113 509	340 189 283	360 113 509	340 189 283
Basic and diluted earnings USD per share	11	1.32	0.81	1.25	0.88

STATEMENT OF COMPREHENSIVE INCOME

(USD 1 000)	Note	Group 2018	Group 2017	Parent 2018	Parent 2017
Profit for the period		476 423	274 787	451 315	299 955
Items which will not be reclassified over profit and loss (net of taxes)					
Actuarial gain/loss pension plan		8	-1	8	-1
Items which may be reclassified over profit and loss (net of taxes)					
Currency translation adjustment		-72 612	25 167	-	-
Reclassification to profit and loss		47 504	-	-	-
Total comprehensive income in period		451 323	299 953	451 323	299 953

STATEMENT OF FINANCIAL POSITION

(USD 1 000)	Note	Group 31.12.2018	Group 31.12.2017	Parent 31.12.2018	Parent 31.12.2017
ASSETS					
Intangible assets					
Goodwill	12	1 860 126	1 860 126	1 860 126	1 860 126
Capitalized exploration expenditures	12	427 439	365 417	427 439	365 417
Other intangible assets	12	2 005 885	1 617 039	2 005 885	1 617 039
Tangible fixed assets					
Property, plant and equipment	12	5 746 275	5 582 493	5 746 275	5 582 493
Financial assets					
Long-term receivables		37 597	40 453	37 597	40 453
Long-term derivatives	21	-	12 564	-	12 564
Other non-current assets	16	10 388	8 398	10 388	1 594 404
Total non-current assets		10 087 710	9 486 491	10 087 710	11 072 497
Inventories					
Inventories	5	93 179	75 704	93 179	75 704
Receivables					
Accounts receivable	14	162 798	99 752	162 798	99 752
Tax receivables	10	11 082	1 586 006	11 082	-
Other short-term receivables	15	360 194	535 518	360 194	535 518
Short-term derivatives	21	17 253	2 585	17 253	2 585
Cash and cash equivalents					
Cash and cash equivalents	17	44 944	232 504	44 944	232 504
Total current assets		689 450	2 532 069	689 450	946 063
TOTAL ASSETS		10 777 160	12 018 560	10 777 160	12 018 560

STATEMENT OF FINANCIAL POSITION

(USD 1 000)	Note	Group 31.12.2018	Group 31.12.2017	Parent 31.12.2018	Parent 31.12.2017
EQUITY AND LIABILITIES					
Equity					
Share capital	18	57 056	57 056	57 056	57 056
Share premium		3 637 297	3 637 297	3 637 297	3 637 297
Other equity		-704 432	-705 756	-704 432	-705 756
Total equity		2 989 920	2 988 596	2 989 920	2 988 596
Non-current liabilities					
Deferred taxes	10	1 800 199	1 307 148	1 800 199	1 307 148
Long-term abandonment provision	20	2 447 558	2 775 622	2 447 558	2 775 622
Provisions for other liabilities	22	107 519	152 418	107 519	152 418
Long-term bonds	19	1 110 488	622 039	1 110 488	622 039
Long-term derivatives	21	26 275	13 705	26 275	13 705
Other interest-bearing debt	23	907 954	1 270 556	907 954	1 270 556
Current liabilities					
Trade creditors		105 567	32 847	105 567	32 847
Accrued public charges and indirect taxes		25 061	27 949	25 061	27 949
Tax payable	10	551 942	351 156	551 942	351 156
Short-term derivatives	21	8 783	7 691	8 783	7 691
Short-term abandonment provision	20	105 035	268 262	105 035	268 262
Short-term interest-bearing debt	23	-	1 496 374	-	1 496 374
Other current liabilities	24	590 860	704 197	590 860	704 197
Total liabilities		7 787 241	9 029 964	7 787 241	9 029 964
TOTAL EQUITY AND LIABILITIES		10 777 160	12 018 560	10 777 160	12 018 560

The Board of Directors and the CEO of Aker BP ASA
Akerkvartalet, 13 March 2019

ØYVIND ERIKSEN
Chairman

ANNE MARIE CANNON
Deputy chair

KJELL INGE RØKKE
Board member

TROND BRANDSRUD
Board member

GRO KIELLAND
Board member

BERNARD LOONEY
Board member

KATE THOMSON
Board member

INGARD HAUGEBERG
Board member

ANETTE HOEL HELGESEN
Board member

ØRJAN HOLSTAD
Board member

TERJE SOLHEIM
Board member

KARL JOHNNY HERSVIK
Chief Executive Officer

STATEMENT OF CHANGES IN EQUITY - GROUP AND PARENT

			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 31.12.2016	54 349	3 150 567	573 083	-88	-115 550	-1 213 154	-755 709	2 449 207
Private placement	2 706	486 729	-	-	-	-	-	489 436
Dividend distributed	-	-	-	-	-	-250 000	-250 000	-250 000
Profit for the period	-	-	-	-	-	274 787	274 787	274 787
Other comprehensive income for the period	-	-	-	-1	25 167	-	25 166	25 166
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	-	-	-	-	-	-450 000	-450 000	-450 000
Profit for the period	-	-	-	-	-	476 423	476 423	476 423
Other comprehensive income for the period	-	-	-	8	-25 108	-	-25 100	-25 100
Equity as of 31.12.2018 (Group and Parent)	57 056	3 637 297	573 083	-81	-115 491	-1 161 943	-704 432	2 989 920

* The main part of the foreign currency translation reserve arose as a result of the change in functional currency in Q4 2014

(USD 1 000)	Note	Group 2018	Group 2017	Parent 2018	Parent 2017
CASH FLOW FROM OPERATING ACTIVITIES					
Profit before taxes		1 804 909	811 128	1 778 222	831 441
Taxes paid		-606 082	-101 115	-606 082	-101 115
Taxes refunded		1 513 394	404 704	1 513 394	140 913
Depreciation	12	752 437	726 670	752 437	726 670
Net impairment losses	12, 13	20 172	52 349	20 172	52 349
Accretion expenses	9, 20	128 737	129 619	128 737	129 619
Interest expenses	9	200 524	156 704	200 524	176 248
Interest paid		-195 659	-145 940	-195 659	-145 940
Changes in derivatives	6, 9	11 558	-34 461	11 558	-34 461
Amortized loan costs	9	29 722	36 900	29 722	36 900
Amortization of fair value of contracts		56 775	11 728	56 775	11 728
Expensed capitalized dry wells	4, 12	65 852	75 401	65 852	75 401
Changes in inventories, accounts payable and receivables		-7 800	-7 583	-7 800	-7 583
Changes in other current balance sheet items		25 031	39 387	51 718	-471
NET CASH FLOW FROM OPERATING ACTIVITIES		3 799 570	2 155 491	3 799 570	1 891 700
CASH FLOW FROM INVESTMENT ACTIVITIES					
Payment for removal and decommissioning of oil fields	20	-242 545	-85 733	-242 545	-85 733
Disbursements on investments in fixed assets	12	-1 312 697	-977 462	-1 312 697	-977 462
Acquisitions of companies (net of cash acquired)		-	-2 055 033	-	-2 055 033
Cash received from sale of licenses		-	170 959	-	170 959
Disbursements on investments in capitalized exploration	12	-128 795	-111 724	-128 795	-111 724
Disbursements on investments in licenses		-463 049	-	-463 049	263 791
NET CASH FLOW USED IN INVESTMENT ACTIVITIES		-2 147 086	-3 058 994	-2 147 086	-2 795 203
CASH FLOW FROM FINANCING ACTIVITIES					
Net drawdown/repayment of long-term debt	23	-380 252	-777 911	-380 252	-777 911
Repayment of bond (DETNOR03)	9, 19	-	-330 000	-	-330 000
Repayment of short-term debt		-1 500 000	-	-1 500 000	-
Net cash received from issuance of new shares	18	-	489 436	-	489 436
Net proceeds from issuance of debt	19, 23	492 423	1 886 885	492 423	1 886 885
Paid dividend		-450 000	-250 000	-450 000	-250 000
NET CASH FLOW FROM FINANCING ACTIVITIES	27	-1 837 829	1 018 410	-1 837 829	1 018 410
Net change in cash and cash equivalents		-185 344	114 906	-185 344	114 906
Cash and cash equivalents at start of period		232 504	115 286	232 504	115 286
Effect of exchange rate fluctuation on cash held		-2 216	2 312	-2 216	2 312
CASH AND CASH EQUIVALENTS AT END OF PERIOD	17	44 944	232 504	44 944	232 504
SPECIFICATION OF CASH EQUIVALENTS AT END OF PERIOD					
Bank deposits and cash		44 944	231 506	44 944	231 506
Restricted bank deposits		-	998	-	998
CASH AND CASH EQUIVALENTS AT END OF PERIOD	17	44 944	232 504	44 944	232 504

General information

Aker BP ASA (Aker BP or the company) is an oil company involved in exploration, development and production of oil and gas on the Norwegian Continental Shelf (NCS).

The company is a public limited liability company registered and domiciled in Norway. Aker BP's shares are listed on Oslo Stock Exchange (Oslo Børs) under the ticker AKERBP. The company's registered business address is Oksenøyveien 10, 1366 Lysaker, Norway.

Aker BP's group consolidated financial statements consist of the parent company Aker BP ASA, the subsidiary Aker BP AS (previously Hess Norge AS) which was liquidated during 2018 and the subsidiary BP Norge AS which was liquidated during 2017. For more information regarding subsidiaries, see Note 3.

The financial statements were approved by the Board of Directors on 13 March 2019 and will be presented for approval at the Annual General Meeting on 11 April 2019.

Note 1 Summary of IFRS accounting principles

1.1 Basis of preparation

The group consolidated and the company's financial statements have been prepared in accordance with the Norwegian Accounting Act and International Financial Reporting Standards as adopted by the EU (IFRS).

The financial statements have been prepared on a historical cost basis with the exception of the following accounting items which are measured on an alternative basis on each reporting date:

- Financial instruments at fair value through profit or loss.
- Loans, receivables and other financial liabilities, which are recognized at amortized cost.

The financial statements have been prepared using uniform accounting principles for equivalent transactions and events taking place on otherwise equal terms.

All amounts have been rounded to the nearest thousand unless otherwise stated. As a result of rounding adjustments, the figures in one or more rows or columns included in the financial statements and notes may not add up to the total of that row or column.

1.2 Functional currency and presentation currency

The functional currency of Aker BP ASA and the presentation currency of the group is USD.

1.3 Important accounting judgments, estimates and assumptions

The preparation of financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that have an effect on the application of accounting principles and on recognized amounts relating to assets and liabilities, to provide information relating to contingent assets and liabilities on the date of the Statement of financial position, and to report revenues and expenses in the course of the accounting period.

The important judgments management has made on the application of accounting principles relate to the following:

Goodwill allocation and methodology for impairment testing

For the purpose of impairment testing, goodwill is allocated to cash-generating unit (CGU), or groups of cash-generating units, that are expected to benefit from the synergies of the business combination from which it arose. The appropriate allocation of goodwill requires management's judgment and may impact the subsequent impairment charge significantly. Although not an IFRS term, "technical goodwill" is used by Aker BP to describe a category of goodwill arising as an offsetting account to deferred tax recognised in business combinations, as described in Section 1.8 below. There are no specific IFRS guidelines pertaining to the allocation of technical goodwill, and management has therefore applied the general guidelines for allocating goodwill for the purpose of impairment testing. In general, technical goodwill is allocated to CGU level for impairment testing purposes, while residual goodwill may be allocated across all CGUs based on facts and circumstances in the business combination.

When performing the impairment test for technical goodwill, deferred tax recognized in relation to the acquired licences reduces the net carrying value prior to the impairment charges. This is done to avoid an immediate impairment of all technical goodwill. When deferred tax from the initial recognition decreases, more goodwill is as such exposed for impairment. Going forward, depreciation of values calculated in the purchase price allocation will result in decreased deferred tax liability.

On selling a licence where the company historically has recognized deferred tax and goodwill in a business combination, both goodwill and deferred taxes from the acquisition are included when calculating gain/loss. When recording impairment of such licences as a result of impairment testing, the same assumptions are applied when measuring the impairment. This avoids a gross up of the impairment with tax, in that the impairment charged to the Income statement will not be higher than the original post-tax amount paid in the business combination.

Accounting estimates are used to determine reported amounts, including the possibility of realizing certain assets, the expected useful life of tangible and intangible assets, the tax expense, etc. Even though these estimates are based on management's best judgment and assessment of previous and current events and actions, the actual results may deviate from the estimates. The estimates and underlying assumptions are reviewed regularly. Changes to the estimates are recognized when new estimates can be determined with sufficient certainty. Changes to accounting estimates are recognized in the period when they arise. The main sources of uncertainty when using estimates for the company relate to the following:

Proven and probable oil and gas reserves

Oil and gas reserves are estimated by the company's experts in accordance with industry standards. The estimates are based on Aker BP's own assessment of internal information and information received from the operators. In addition, proved and probable reserves are certified by an independent third party. Proven and probable oil and gas reserves consist of the estimated quantities of crude oil, natural gas and condensates shown by geological and technical data to be recoverable with reasonable certainty from known reservoirs under existing economic and operational conditions, i.e. on the date that the estimates are prepared. Current market prices are used in the estimates, except for existing contractual future price changes.

Proven and probable reserves and production volumes are used to calculate the depreciation of oil and gas fields by applying the unit-of-production methodology. Reserve estimates are also used as basis for impairment testing of licence-related assets. Changes in petroleum prices and cost estimates may change reserve estimates and accordingly economic cut-off, which may impact the timing of assumed decommissioning and removal activities. Changes to reserve estimates can also be caused by updated production and reservoir information. Future changes to proven and probable oil and gas reserves can have a material effect on depreciation, life of field, impairment of licence-related assets, and operating results.

Successful Effort Method - exploration

Aker BP's accounting policy is to temporarily recognize expenses relating to the drilling of exploration wells in the Statement of financial position as capitalized exploration expenditures, pending an evaluation of potential oil and gas discoveries. If resources are not discovered, or if recovery of the resources is considered technically or commercially unviable, the costs of exploration wells are expensed. Decisions as to whether this expenditure should remain capitalized or be expensed during the period, may materially affect the operating result for the period.

Acquisition costs

Expenses relating to the acquisition of exploration licences are capitalized and assessed for impairment if there are indications of impairment. See Items 1.11 and 1.12 for further details.

Fair value measurement

From time to time, the fair values of non-financial assets and liabilities are required to be determined, e.g. when the entity acquires a business, determines allocation of purchase price in an asset deal or where an entity measures the recoverable amount of an asset or CGU at fair value less cost to sell. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. The group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. The fair value of oil fields in production and development phase is normally based on discounted cash flow models, where the determination of the different input in the model requires significant judgment from management, as described in the section below regarding impairment.

Impairment/reversal of impairment

Aker BP has significant investments in long-lived assets. Changes in the expected future value/cash flow of individual assets can result in the book value of some assets being impaired to estimated recoverable value. Impairment losses other than those relating to goodwill must be reversed if the conditions for the impairment are no longer present. Considerations regarding whether an asset is actually impaired or whether the impairment losses should be reversed can be complicated and are based on judgement and assumptions. The complexity of the issue can, for example, relate to the modelling of relevant future cash flows to determine the asset's value in use, decide on measurement units and establish the asset's net sales value.

The evaluation of impairment requires long-term assumptions concerning a number of often volatile economic factors, including future oil prices, oil production, currency exchange rates and discount rates. Such assumptions require the estimation of relevant factors such as forward price curves (oil), long-term price assumptions, the level of capex and opex, production estimates and residual asset values. Likewise, establishing an asset's net sales value requires careful assessment unless information about net sales value can be obtained from an actual observable market. See Note 12 ' Tangible fixed assets and intangible assets' and Note 13 'Impairments' for details about impairment.

Decommissioning and removal obligations

The company has considerable obligations relating to decommissioning and removal of offshore installations at the end of the production period. Obligations associated with decommissioning and removal of long-term assets are recognized at present value of future expenditures on the date they are incurred. At the initial recognition of an obligation, the estimated cost is capitalized as production plant and depreciated over the useful life of the asset (typically by unit-of-production). It is difficult to estimate the costs for decommissioning and removal at initial recognition as these estimates are based on currently applicable laws and regulations, and are dependent on technological developments. Many decommissioning and removal activities will take place in the distant future, and the technology and related costs are constantly changing. The estimates include costs based on expected removal concepts based on known technology and estimated costs of maritime operations, hiring of heavy-lift barges and drilling rigs. As a result, the initial recognition of the obligation in the accounts, the related costs capitalized in the Statement of financial position for decommissioning and removal and subsequent adjustment of these items, involve careful consideration. Based on the described uncertainty, there may be significant adjustments in estimates of liabilities that can affect future financial results. See Note 20 for further details about decommissioning and removal obligations.

Income tax

The company may incur significant amounts of income tax payable or receivable, and recognizes significant changes to deferred tax or deferred tax assets. These figures are based on management's interpretation of applicable laws and regulations, and on relevant court decisions. The quality of these estimates is highly dependent on management's ability to properly apply a complex set of rules and identify changes to the existing legal framework. See Note 10 for details about the deferred tax and taxes payable.

1.4 Foreign currency transactions

Transactions and balances

Transactions in foreign currencies are translated using the exchange rate on the transaction date. Monetary items in foreign currencies in the Statement of financial position are translated using the exchange rates at the end of the period. Foreign exchange gains and losses are recognized on an ongoing basis in the accounting period. Non-monetary items that are measured in terms of historical costs in a foreign currency are translated using the exchange rates on the dates of the initial transactions. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates on the date when the fair value is determined.

Group companies

The results and financial position of group companies that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

(i) Assets and liabilities for each balance sheet presented are translated based on the exchange rates at the balance sheet date.

(ii) Revenues and expenses for each Income statement presented are translated at average exchange rate for the period. However, if this average is not a reasonable approximation of the cumulative effect on the prevailing rates on the actual transaction dates, revenues and expenses are translated using the foreign exchange rates on the specific transaction date.

(iii) Equity transactions are translated at the exchange rate on the transaction date.

All resulting exchange rate differences are recognized in other comprehensive income. The same method has been used for translating the parent company financial statements to USD as presentation currency for periods prior to the change in functional currency to USD.

1.5 Revenue recognition

Revenues from petroleum products in which the company has an interest with other producers are recognized on the basis of the company's proportionate share of production during the period, regardless of actual sales (entitlement method).

This is achieved by applying the following approach in dealing with imbalances between actual sales and entitlements:

- The excess of product sold during the period over the participant's ownership share of production from the property is recognized by the overlift party as a liability (deferred revenue) and not as revenue. Conversely, the underlift party would recognize an underlift asset (receivable) and report corresponding revenue.
- Differences between oil lifted and sold: petroleum overlifts are presented as current liabilities, while petroleum underlifts are presented as short-term receivables. The value of overlift/underlift is set at the estimated sales value, minus estimated sales costs.

Other revenues are recognized when the goods or services are delivered and material risk and control are transferred.

Gain on asset disposals as described in Section 1.9 is included in other operating income.

Tariff revenue from processing of oil and gas is recognized as earned in line with underlying agreements.

Revenue is presented net of customs and excise taxes on petroleum products.

Dividends are recognized when the shareholders' dividend rights are approved by the Annual General Meeting.

Interest is taken to income based on the effective interest method as it is earned.

1.6 Interests in joint arrangements

IFRS defines a joint arrangement as an arrangement over which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities (being those that significantly affect the returns of the arrangement) require unanimous consent of the parties sharing control.

The company has interests in licences on the Norwegian Continental Shelf. Under IFRS 11 Joint Arrangements, a joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement. The company recognizes investments in joint operations (oil and gas licences) by reporting its share of related revenues, expenses, assets, liabilities and cash flows under the respective items in the company's financial statements.

For those licences that are not deemed to be joint arrangements pursuant to the definition in IFRS 11 as there is no joint control, the company recognizes its share of related expenses, assets, liabilities and cash flows on a line-by-line basis in the financial statements in accordance with applicable IFRSs.

1.7 Classification in statement of financial position

Current assets and current liabilities include items that fall due for payment less than a year from the end of the reporting period and items relating to the business cycle. Next year's instalments on long-term liabilities are classified as current liabilities. Financial investments in shares are classified as current assets, while strategic investments are classified as non-current assets.

1.8 Business combinations and goodwill

In order to consider an acquisition as a business combination, the acquired asset or groups of assets must constitute a business (an integrated set of operations and assets conducted and managed for the purpose of providing a return to the investors). The combination consists of inputs and processes applied to these inputs that have the ability to create output.

Acquired businesses are included in the financial statements from the transaction date. The transaction date is defined as the date on which the company achieves control over the financial and operating assets. This date may differ from the actual date on which the assets are transferred.

Comparative figures are not adjusted for acquired, sold or liquidated businesses.

For accounting purposes, the acquisition method is used in connection with the purchase of businesses. Acquisition cost equals the fair value of the assets used as consideration, including contingent consideration, equity instruments issued and liabilities assumed in connection with the transfer of control. Acquisition cost is measured against the fair value of the acquired assets and liabilities. Identifiable intangible assets are included in connection with acquisitions if they can be separated from other assets or meet the legal contractual criteria. If the acquisition cost at the time of the acquisition exceeds the fair value of the acquired net assets (when the acquiring entity achieves control of the transferring entity), goodwill arises.

If the fair value of the net identifiable assets acquired exceeds the acquisition cost on the acquisition date, the excess amount is taken to the Income statement immediately.

Goodwill is allocated to the CGUs or groups of CGUs that are expected to benefit from synergy effects of the acquisition. The allocation of goodwill may vary depending on the basis for its initial recognition.

The main part of the company's goodwill is related to the requirement to recognize deferred tax for the difference between the assigned fair values and the related tax base ("technical goodwill"). The fair value of of the company's licences, all of which are located on the Norwegian Continental Shelf, are based on cash flows after tax. This is because these licences are only sold in an after-tax market based on decisions made by the Norwegian Ministry of Finance pursuant to the Petroleum Taxation Act Section 10. The purchaser is therefore not entitled to a tax deduction for the consideration paid over and above the seller's tax values. In accordance with IAS 12 paragraphs 15 and 24, a provision is made for deferred tax corresponding to the difference between the acquisition cost and the transferred tax depreciation basis. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a technical effect of deferred tax. Technical goodwill is tested for impairment separately for each CGU which give rise to the technical goodwill. A CGU may be individual oil fields, or a group of oil fields that are connected to the same infrastructure/production facilities.

The estimation of fair value and goodwill may be adjusted up to 12 months after the takeover date if new information has emerged about facts and circumstances that existed at the time of the takeover and which, had they been known, would have affected the calculation of the amounts that were included from that date.

Acquisition-related costs, except costs to issue debt or equity securities, are expensed as incurred.

1.9 Acquisitions, sales and licence swaps

On acquisition of a licence that involves the right to explore for and produce petroleum resources, it is considered in each case whether the acquisition should be treated as a business combination (see Item 1.8) or an asset purchase. Generally, purchases of licences in a development or production phase will be regarded as a business combination. Other licence purchases regarded as asset purchases are described below.

Oil and gas production licences

For licences in the development phase, the acquisition cost is allocated between capitalized exploration expenses, licence rights and production plant.

When entering into agreements regarding the purchase/swap of assets, the parties agree on an effective date for the takeover of the net cash flow (usually 1 January in the calendar year which would also normally be the effective date for tax purposes). In the period between the effective date and the completion date, the seller will include its sold share of the licence in the financial statements. In accordance with the purchase agreement, there is a settlement with the seller of the net cash flow from the asset in the period from the effective date to the completion date (pro & contra settlement). The pro & contra settlement will be adjusted to the seller's losses/gains and to the assets for the purchaser, in that the settlement (after a tax reduction) is deemed to be part of the consideration in the transaction. Revenues and expenses from the relevant licence are included in the purchaser's Income statement from the completion date, as defined in 1.8 above.

For tax purposes, the purchaser will include the net cash flow (pro & contra) and any other income and costs as from the effective date.

When acquiring licences that are defined as asset acquisitions, no provision is made for deferred tax.

Farm-in agreements

Farm-in agreements are usually entered into in the exploration phase and are characterised by the transferor waiving future financial benefits in the form of reserves, in exchange for reduced future financing obligations. For example, a licence interest is taken over in return for a share of the transferor's expenses relating to the drilling of a well. In the exploration phase, the company normally accounts for farm-in agreements on a historical cost basis, as the fair value is often difficult to determine.

Swaps

Swaps of assets are calculated at the fair value of the asset being surrendered, unless the transaction lacks commercial substance, or neither the fair value of the asset received, nor the fair value of the asset surrendered, can be effectively measured. In the exploration phase, the company normally recognizes swaps based on historical cost, as the fair value often is difficult to measure.

1.10 Unitizations

According to Norwegian law, a unitization is required if a petroleum deposit extends over several production licences and these production licences have a different ownership representation. Consensus must be achieved with regard to the most rational coordination of the joint development and ownership distribution of the petroleum deposit. A unitization agreement shall be approved by the Ministry of Petroleum and Energy.

The company recognizes unitizations in the exploration phase based on historical cost, as the fair value often is difficult to measure. For unitizations involving licences outside the exploration phase, it has to be considered whether the transaction has commercial substance. If so, the unitization is recognized at fair value.

1.11 Tangible fixed assets and intangible assets

General

Tangible fixed assets are recognized on a historical cost basis. Depreciation of assets other than oil and gas fields is calculated using the straight-line method over estimated useful lives and adjusted for any impairment or change in residual value, if applicable.

The book value of tangible fixed assets consists of acquisition cost after deduction of accumulated depreciation and impairment losses. Expenses relating to leased premises are capitalized and depreciated over the remaining lease period if the recognition criteria for an asset have been met.

The expected useful lives of tangible fixed assets are reviewed annually, and in cases where these differ significantly from previous estimates, the depreciation period is changed accordingly. Changes to estimates are included prospectively in that the change is recognized in the period in which it occurs, and in future periods if the change affects both.

The residual value of an asset is the estimated amount that the company would obtain from disposal of the asset, after deduction of the estimated costs of disposal, if the asset was already of the age and in the condition expected at the end of its useful life.

Ordinary repair and maintenance costs relating to day-to-day operations are charged to the Income statement in the period in which they are incurred. The costs of major repairs and maintenance are included in the asset's book value.

Gains and losses relating to the disposal of assets are determined by comparing the selling price with the book value, and are included in other operating income/expenses. Assets held for sale are reported at the lower of the book value and the fair value less cost to sell.

Operating assets related to petroleum activities

Exploration and development costs relating to oil and gas fields

Capitalized exploration expenditures are classified as intangible assets and reclassified to tangible assets at the start of the development. For accounting purposes, the field is considered to enter the development phase when the technical feasibility and commercial viability of extracting hydrocarbons from the field are demonstrable, normally at the time of concept selection. All costs relating to the development of commercial oil and/or gas fields are recognized as tangible assets. Pre-operational costs are expensed as they are incurred.

The company employs the 'successful efforts' method to account for exploration and development costs. All exploration costs (including seismic shooting, seismic studies and 'own time'), with the exception of acquisition costs of licences and drilling costs for exploration wells, are expensed as incurred. When exploration drilling is ongoing in a period after a reporting date and the result of the drilling is subsequently not successful, the capitalized exploration cost as of the reporting date is expensed if the evaluation of the well is completed before the date when the financial statement is authorized for issue.

Drilling cost for exploration wells are temporarily capitalized pending the evaluation of potential discoveries of oil and gas resources. Such costs can remain capitalized for more than one year. The main criteria are that there must be plans for future activity in the licence or that a development decision is expected in the near future. If no resources are discovered, or if recovery of the resources is considered technically or commercially unviable, expenses relating to the drilling of exploration wells are charged to expense.

Acquired licence rights are recognized as intangible assets at the time of acquisition. Acquired licence rights related to fields in the exploration phase remain as intangible assets also when the related fields enter the development or production phase.

Depreciation of oil and gas fields

Capitalized exploration and evaluation expenditures, development expenditures from construction, installation or completion of infrastructure facilities such as platforms, pipelines and production wells, and field-dedicated transport systems for oil and gas are capitalized as production facilities and are depreciated using the unit-of-production method based on proven and probable developed reserves expected to be recovered from the area during the concession or contract period. Acquired assets used for the recovery and production of petroleum deposits, including licence rights, are depreciated using the unit-of-production method based on proven and probable reserves. The reserve basis used for depreciation purposes is updated at least once a year. Any changes in the reserves affecting unit-of-production calculations are reflected prospectively.

1.12 Impairment

Tangible fixed assets and intangible assets

Tangible fixed assets and intangible assets (including licence rights, exclusive of goodwill) with a finite useful life will be assessed for potential loss in value when events or changes in the circumstances indicate that the book value of the assets is higher than the recoverable amount.

The valuation unit used for assessment of impairment will depend on the lowest level at which it is possible to identify cash inflows that are independent of cash inflows from other groups of fixed assets. For oil and gas assets, this is carried out at the field or licence level. The loss in value for capitalized exploration costs is assessed for each well. Impairment is recognized when the book value of an asset or a CGU exceeds the recoverable amount. The recoverable amount is the higher of the asset's fair value less cost of disposal and value in use. When assessing the value in use, the expected future cash flow is discounted to the net present value by applying a discount rate after tax that reflects the current market valuation of the time value of money and the specific risk related to the asset. The discount rate is derived from the Weighted Average Cost of Capital (WACC).

For producing licences and licences in a development phase, the recoverable amount is calculated by discounting future cash flows after tax. Future cash flows are determined in the various licences based on the production profile compared to estimated proven and probable remaining reserves. The lifetime of the field for the purpose of impairment testing, is normally determined by the point in time when the operating cash flow from the field becomes negative.

For acquired exploration licences, an initial assessment as described in Section 1.11 above is performed – an assessment of whether plans for further activities have been established or, if applicable, an evaluation of whether development will be decided on in the near future.

A previously recognized impairment can only be reversed if changes have occurred in the estimates used for the calculation of the recoverable amount. However, the reversal cannot be to an amount that is higher than it would have been if the impairment had not previously been recognized. Such reversals are recognized in the Income statement. After a reversal, the depreciation amount is adjusted in future periods in order to distribute the asset's revised book value, minus any residual value, on a systematic basis over the asset's expected remaining life.

Goodwill

Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that the value may be impaired.

Impairment is recognized if the recoverable amount of the CGU (or group of CGUs) to which the goodwill is related is less than the book value, including associated goodwill and deferred tax as described in Section 1.8. Losses relating to impairment of goodwill cannot be reversed in future periods. The company performs its annual impairment test of goodwill in the fourth quarter.

On selling a licence where the company historically has recognized deferred tax and goodwill in a business combination, both goodwill and deferred taxes from the acquisition are included when calculating gain/loss. When recording impairment of such licences as a result of impairment testing, the same assumptions are applied when measuring the impairment. This avoids gross up of the impairment with tax, in that the impairment charged to the Income statement will not be higher than the original post tax amount paid in the business combination.

1.13 Financial instruments

The company has classified the financial instruments into the following categories of financial assets and liabilities:

- Financial assets at fair value designated as such upon initial recognition
- Cash and receivables
- Financial liabilities at fair value designated as such upon initial recognition
- Financial liabilities measured at amortized costs

Financial assets with fixed or determinable cash flows that are not quoted in an active market are classified as loans and receivables.

Financial liabilities that do not form part of the "held for trading purposes" category and which have not been designated as being at fair value with changes in value through profit or loss are classified as other financial liabilities.

For financial instruments not traded in an active market, the fair value is determined by using appropriate valuation techniques. Such techniques may include using recent arm's length market transaction; reference to the current fair value of other instruments that is substantially the same; discounted cash flow analysis or other valuation models.

An analysis of fair values of financial instruments and further details as to how they are measured are provided in Note 27.

1.14 Impairment of financial assets

Financial assets that are assessed at amortized cost are impaired when, based on objective evidence, it is likely that the instrument's cash flows have been negatively affected by one or more events that have occurred after the initial recognition of the instrument. In addition, the loss event must have an impact on estimated future cash flows that can be reliably estimated. The impairment is recognized in the Income statement. Should the reason for the impairment subsequently cease to exist, and this can be objectively linked to an event taking place after the impairment of the asset, the previous impairment shall be reversed. The reversal shall not cause the book value of the financial asset to exceed the amount that the amortized cost would have been if the impairment had not been recognized at the time when the impairment was reversed. Reversals of previous impairments are presented on the same line item as the impairment.

1.15 Research and development

Research consists of original, planned studies carried out with a view to achieving new scientific or technical knowledge or understanding. Development consists of the application of information gained through research, or of other knowledge, to a plan or design for the production of new or significantly improved materials, facilities, products, processes, systems or services before commercial production or use commences.

The licence system on the Norwegian Continental Shelf stimulates research and development activities. The company is mainly involved in research and development through projects financed by participants in the licences.

1.16 Presentation of payroll and administration costs

The company presents its payroll and operating costs based on the functions in development, operational and exploration activities respectively, based on allocation of registered hours worked. As a basis, the company uses gross payroll and operating expenses reduced by the amounts already invoiced to operated licences.

1.17 Lease agreements

Financial lease agreements

Lease agreements in which the company accepts the main risk and returns incidental to ownership of the assets are financial lease agreements. At the start of the lease period, financial lease agreements are calculated at an amount corresponding to the lowest of the fair value and the minimum present value of the lease. When calculating the lease agreement's net present value, the implicit interest rate in the lease agreement is used provided that it can be calculated; otherwise, the company's incremental borrowing rate is used. Direct costs in connection with the establishment of the lease agreement are included in the asset's cost price.

Financial lease agreements are treated as tangible fixed assets in the Statement of financial position and have the same depreciation period as the company's other depreciable assets. If it cannot be assumed with reasonable certainty that the company will take over ownership of the asset after the expiry of the lease, the asset is depreciated over whichever is the shorter of the contract period of the lease agreements and the asset's expected useful life.

Operating lease agreements

Lease agreements in which the main risk and returns associated with the ownership of the asset are not transferred, are classified as operating lease agreements. Rental payments are classified as operating expenses and are recognized on a straight-line basis over the contract period.

1.18 Trade debtors

Trade debtors are recognized in the Statement of financial position at nominal value after a deduction for the provision for credit losses. The provision for credit losses is calculated on the basis of an individual valuation of each trade debtor. Known losses on receivables are expensed as incurred.

1.19 Borrowing costs

Borrowing costs that can be directly ascribed to procurement, processing or production of a qualifying asset shall be capitalized as part of the asset's acquisition cost. Borrowing cost is only capitalized during the development phase. Other borrowing costs are expensed in the period in which they are incurred.

A qualifying asset is one that necessarily takes a substantial period of time to be made ready for its intended use or sale. Qualifying assets are generally those that are subject to major development or construction projects.

1.20 Inventories

The inventory mainly consists of equipment for the drilling of exploration and production wells and are valued at the lower of cost price (based on weighted average cost) and net realizable value. Costs include raw materials, freight and direct production costs in addition to some indirect costs.

1.21 Cash and cash equivalents

Cash and cash equivalents include cash, bank deposits, and other short-term highly liquid investments with an original due date of three months or less. Bank overdrafts are included in the Statement of financial position as short-term loans.

1.22 Interest-bearing debt

All borrowings are initially recognized at transaction price, which equals the fair value of the amount received minus issuing costs relating to the loan.

Subsequently, interest-bearing borrowings are valued at amortized cost using the effective interest method; the difference between the transaction price (after transaction costs) and the face value is recognized in the Income statement during the period until the loan falls due. Amortized costs are calculated by considering all issue costs and any discount or premium on the settlement date.

1.23 Tax

General

Tax payable/tax receivable for the current and previous periods is based on the amounts receivable from or payable to the tax authorities.

Tax consists of tax payable and changes in deferred tax. Deferred tax/tax benefits are calculated on the basis of the differences between book value and tax basis values of assets and liabilities, with the exception of temporary differences on acquisition of licences that is defined as asset purchase.

The book value of deferred tax benefits is assessed and reduced insofar as it is no longer probable that future earnings or current tax regulations will make it possible to utilise the benefit. Deferred tax benefits that are not capitalized will be re-evaluated on each date of Statement of financial position and capitalized insofar as it is probable that future earnings or current tax regulations will make it possible to utilise the benefit.

Deferred tax and tax benefits are measured using the expected tax rate when the tax benefit is realised or the tax liability is met, based on tax rates and tax regulations that have been enacted or substantively enacted by the end of the reporting period.

Tax payable and deferred tax is recognized directly against equity or other comprehensive income insofar as the tax items are related to equity transactions or items of other comprehensive income.

Deferred tax and tax benefits are presented net, where netting is legally permitted and the deferred tax benefit and liability are related to the same tax subject and are payable to the same tax authorities.

Functional currency

The company's functional currency is USD, while it is a statutory requirement to calculate the current tax based on NOK functional currency. This may impact the tax rate when the exchange rate between NOK and USD varies. The revaluation of tax receivable and payable is presented as foreign exchange gain/loss, while the impact on deferred tax from revaluation of tax balances is presented as tax expense / income.

Petroleum taxation

As a production company, Aker BP is subject to the special provisions of the Petroleum Taxation Act. Revenues from activities on the Norwegian Continental Shelf are liable to ordinary company tax and special tax. The tax rate for general corporate tax was 24 per cent in 2017, and was changed to 23 per cent in 2018. The rate for special tax was 54% and 55% correspondingly. From 1 January 2019, the corresponding rates have changed to 22 and 56 per cent, which has impacted the deferred tax calculation in 2018.

Tax depreciation

Pipelines and production facilities can be depreciated by up to 16 2/3 per cent annually, i.e., using the straight-line method over six years. Depreciation can be started when the expenses are incurred. When the field stops producing, the remaining cost price can be included as a deduction in the final year.

Uplift

Uplift is a special income deduction in the basis for calculation of special tax. The uplift is calculated on the basis of investments in pipelines and production facilities, and can be regarded as an extra depreciation deduction in the special tax basis. The uplift rate was 5.4 per cent in 2017, 5.3 per cent in 2018 and 5.2 per cent from 2019 over a period of four years, totalling 21.6 per cent from 2017, 21.2 per cent from 2018 and 20.8 per cent from 2019. Uplift is recognized in the year it is deducted in the companies' tax returns, and this has a similar effect on the tax for the period as a permanent difference.

Financial items

Interest on debt with associated currency losses/gains (net financial expenses on interest-bearing debt) is distributed between the offshore and onshore tax jurisdictions. The offshore interest deduction is calculated as the net financial costs of interest-bearing debt multiplied by 50 per cent of the ratio between net asset value for tax purposes allocated to the offshore tax jurisdictions as of 31 December in the income year and the average interest-bearing debt through the income year.

Remaining financial expenses, currency losses and all interest income as well as currency gains are allocated to the onshore jurisdiction.

Uncovered losses in the onshore tax jurisdictions resulting from the distribution of net financial items can be allocated to the offshore tax jurisdictions and deducted from regular income.

Only 50 per cent of other losses in the onshore tax jurisdictions are permitted to be reallocated to the offshore tax jurisdictions as deductions in regular income.

Exploration expenses

Companies may claim a refund from the State for the tax value of exploration expenses incurred insofar as these do not exceed the year's tax-related loss allocated to the offshore activities. The refund is included under 'Tax receivable' in the Statement of financial position.

Tax loss

Companies subject to special tax may, without time limitations, carry forward losses with the addition of interest. A corresponding rule also applies to unused uplift. The tax position can be transferred on realisation of the company or merger. Alternatively, disbursement of the tax value can be claimed from the State if the company ceases petroleum activities. The tax loss will thus be reclassified from deferred tax to current tax at the time the petroleum activity ceases, or is transferred to another company.

1.24 Employee benefits

Pension schemes

The company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("lov om obligatorisk tjenestepensjon"). The company's pension scheme meets the requirements of that law.

Gains and losses on curtailment or settlement of a defined-benefit pension scheme are included in the Income statement when the curtailment or settlement occurs. The company is making contributions to the pension plan for full-time employees equal to 7 per cent for salary up to 7.1 G and 25.1 per cent between 7.1 and 12 G. The pension premiums are charged to expenses as they are incurred.

An early retirement scheme (AFP) has been introduced for all employees. The scheme is a multi-employer defined benefit plan, but is accounted for as a defined contribution pension, and premiums are expensed as incurred.

1.25 Provisions

A provision is recognized in the accounts when the company incurs a commitment (legal or self-imposed) as a result of a past event and it is probable that financial settlement will take place as a result of this commitment, and the amount can be reliably calculated. Provisions are evaluated at each period end and are adjusted to reflect the best estimate.

An onerous contract is a contract in which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it. A provision for onerous contracts is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract.

If the time effect is considerable, the provisions are discounted using a discount rate before tax that reflects the market's pricing of the time value of the amount and the risk specifically associated with the commitment. On discounting, the book value of the provisions is increased in each period to reflect the change in time relative to the due date of the commitment. The increase is expensed as an accretion expense.

Decommissioning and removal costs:

In accordance with the licence terms and conditions for the licences in which the company participates, the Norwegian State can require licence owners to remove the installation in whole or in part when production ceases or the licence period expires.

In the initial recognition of the decommissioning and removal obligations, the company provides for the net present value of future costs related to decommissioning and removal. A corresponding asset is capitalized as a tangible fixed asset and depreciated using the unit-of-production method. Changes in the time value (net present value) of the obligation related to decommissioning and removal accretion are charged to income as financial expenses and increase the balance-sheet liability related to future decommissioning and removal expenses. Changes in the best estimate for expenses related to decommissioning and removal are recognized in the Statement of financial position. The discount rate used in the calculation of the fair value of the decommissioning and removal obligation is the risk-free rate with the addition of a credit risk element.

1.26 Segment

Since its formation, the company has conducted its entire business in one and the same segment, defined as exploration for and production of petroleum in Norway. The company conducts its activities on the Norwegian Continental Shelf, and management follows up the company at this level. The financial information relating to geographical distribution and large customers is presented in Note 3.

1.27 Earnings per share

Earnings per share are calculated by dividing the ordinary profit/loss attributable to ordinary equity holders of the parent entity by the weighted average number of the total outstanding shares. Shares issued during the year are weighted in relation to the period in which they have been outstanding. Diluted earnings per share is calculated as the profit/loss for the year divided by the weighted average number of outstanding shares during the period, adjusted for the dilution effect of any share options.

1.28 Contingent liabilities and assets

Except for in the event of a business combination, neither contingent liabilities nor contingent assets are recognized.

A contingent liability is a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity; or a present obligation that arises from past events but is not recognized because it is not probable that an outflow of resources embodying economic benefits will be required to settle the obligation or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are disclosed with the exception of contingent liabilities where the probability of the liability having to be settled is remote.

Contingent assets are possible asset that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity. Information about such contingent assets is provided if inflow of economic benefits is probable.

1.29 Changes to accounting standards and interpretations that:

Have entered into force:

IFRS 9 Financial instruments

IFRS 9 Financial Instruments, which replaces IAS 39 Financial Instruments: Recognition and Measurement, was issued in July 2014. The standard introduced new requirements for classification and measurement, impairment, and hedge accounting. IFRS 9 became effective for annual periods beginning on or after 1 January 2018, with early application permitted. Except for hedge accounting, retrospective application is required, but comparative information is not compulsory. For hedge accounting, the requirements are generally applied prospectively, with some limited exceptions. Based on the group’s financial instruments and the related accounting treatment during 2018, the adoption of IFRS 9 did not have any significant impact on the group financial statements.

IFRS 15 Revenue from contracts with customers

IFRS 15 Revenue from Contracts with Customers was issued in May 2014 and established a new five-step model that applies to revenue arising from contracts with customers. Under IFRS 15, revenue is recognized at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer.

The new revenue standard superseded all previous revenue recognition requirements under IFRS, including IAS 18 *Revenue* . Either a full or modified retrospective application was required for annual periods beginning on or after 1 January 2018 with early adoption permitted. The group has applied the modified retrospective approach.

Under IFRS 15, revenue is recognised when the customer obtains control of the liquids or gas, which will ordinarily be at the point of delivery when title passes. The changes in over/underlift balances included in revenues under the company's entitlement method do not meet the IFRS 15 definition of revenue from contracts with customers, and so has been classified as 'Other revenues'. These 'Other revenues' has been aggregated with the IFRS 15 revenues from contract with customers and presented as a single line item 'Petroleum Revenues' in the Income Statement, with details provided in the note disclosures. Hence, there has been no changes to reported 'Petroleum Revenues' in the Income Statement following the implementation of IFRS 15. Neither there has been any impact on the profit, cash flows or equity of Aker BP as a result of the adoption of IFRS 15.

The interpretation of IFRS 15 is currently being discussed and clarified in IFRIC meetings, and the group closely follows these discussions to confirm that the current accounting treatment of changes in over/underlift is consistent with IFRS 15.

Have been issued but have not entered into force:

A number of standards and interpretations are issued, but not yet effective as of 31 December 2018. Those that may have an impact on the group are disclosed below.

IFRS 16 Leases

IFRS 16 Leases was issued in January 2016 and replaces the current lease accounting standard, IAS 17 Leases, including related interpretations. The new standard changes introduce a single on-balance sheet accounting model for all leases, which will result in the recognition of a lease liability and a right of use asset ("RoU asset) in the balance sheet. The standard is effective from 1 January 2019.

The Company will apply the modified retrospective approach with no restatement of comparative figures. The lease liability at the date of the initial application will be measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate of approximately 5 per cent. The borrowing rate is derived from the terms of the Company's existing credit facilities. RoU assets will be depreciated over the lease term as this is ordinarily shorter than the useful life of the assets.

The Company will apply the exemption for short term leases (12 months or less) and low value leases. This means that related lease payments will not be recognized in the balance sheet, but expensed or capitalized in line with the accounting treatment for other non-lease expenses. The inclusion of non lease components may vary across different lease categories, but for the most material class of assets (rigs), the Company will exclude the non-lease components when measuring the lease liability.

The Company may enter into lease contracts as an operator on behalf of a license, and will for such leases only recognize its net share of the related lease liability. Whether a contract is entered into on behalf of the license is subject to a contract specific assessment, but the general principle is that there needs to be a direct link between the lease contract and the license or field on which the RoU asset shall be used. Other lease contracts, such as offices and supply vessels not linked to specific fields, will be recognized on a gross basis although the related cashflows are charged to the license partners, typically via cost pools. For such contracts, the partner's share of the cost recovered by the Company will be presented as other income.

The Company may enter into lease contracts in its own name at the initial signing, and subsequently allocate the related RoU asset to operated licenses. In such cases, the license allocation will normally be the basis for determining both the commencement and the duration of the lease (and application of the short term lease exemption).

The lease liability and corresponding RoU asset is estimated to USD 400 million at initial recognition on 1 January 2019. Existing onerous lease contract values (recognized based on IFRS 3 in previous years business combinations) of approximately USD 150 million, will reduce the value of the corresponding RoU asset. No impact on equity is expected upon transition. The amount is estimated based on Aker BP's current interpretation of IFRS 16 as described above, which may change in future in response to authoritative guidance or industry practice. The estimate is lower than the lease liability as disclosed in note 25, with the difference mainly relating to short term leases excluded from IFRS 16, discounting effect and non-lease elements that will not be included in the lease liability under IFRS 16, but are included under IAS 17.

The IFRS 16 impact on the income statement is expected to be immaterial in 2019, as the majority of the RoU assets are expected to be used in activity not charged to the income statement, such as field development (including production drilling) and plugging and abandonment. The main impact on the statement of cash flows is that lease payments will generally be presented under financing activities whilst they have been presented as operating or investing activities under IAS17.

Note 2 Overview of subsidiaries

Aker BP ASA has three subsidiaries which are not consolidated in the group accounts in 2018 due to materiality considerations:

Det norske oljeselskap AS (100 per cent)

Det norske oljeselskap AS, previously Marathon Oil Norge AS, was acquired by Aker BP in October 2014. All activity was transferred to Aker BP on 31 October 2014. As of year-end 2018, the only remaining asset in this company is cash equivalents reflecting the share capital amounting to USD 1.0 million.

Alvheim AS (65 per cent)

The sole purpose of Alvheim AS is to act as legal owner of MST Alvheim, the floating production facility which is used to produce oil and gas from the Alvheim fields. The costs of and benefits from operating the MST Alvheim will be carried by the partners in the Alvheim field. Hence, Alvheim AS only has the formal ownership rather than the actual value of the production facilities. Aker BP has a 65 per cent share in Alvheim AS, which corresponds to the ownership in the Alvheim field.

Sandvika Fjellstue AS (100 per cent)

Sandvika Fjellstue AS owns a conference centre used by Aker BP, located in Sandvika in Verdal.

The activity in Aker BP AS (previously Hess Norge AS) was transferred to Aker BP in 2017, and Aker BP AS was liquidated on 28 November 2018.

Note 3 Segment information

The company's business is entirely related to exploration for and production of petroleum in Norway. The company's activities are considered to have a homogeneous risk and return profile before tax, and the business is located in the geographical area Norway. The company operates within a single operating segment which matches the internal reporting to the company's executive management. In 2018 the company had sales transactions with 2 customers with more than 10% of total sales, which accounted for USD 3 297 million and USD 380 million for both the group and parent. In 2017 the company had sales transactions with two customers with more than 10% of the total sales, which accounted for USD 1 147 million and USD 757 million for both the group and parent.

Note 4 Exploration expenses

	Group		Parent	
Breakdown of exploration expenses (USD 1 000)	2018	2017	2018	2017
Seismic	95 458	53 283	95 458	53 283
Area fees	13 822	16 589	13 822	16 589
Field evaluation	79 323	40 162	79 323	40 162
Dry well expenses	65 852	75 401	65 852	75 401
Other exploration expenses	41 453	40 267	41 453	40 267
Total exploration expenses	**295 908**	**225 702**	**295 908**	**225 702**

Note 5 Inventories

The inventory mainly consists of equipment for the drilling of exploration and production wells.

	Group		Parent	
Inventory value (USD 1 000)	2018	2017	2018	2017
Inventories - measured at cost	111 896	94 436	111 896	94 436
Provision for obsolete equipment	18 716	18 732	18 716	18 732
Book value of inventories	**93 179**	**75 704**	**93 179**	**75 704**

Note 6 Income

Breakdown of petroleum revenues (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Sales of liquids	3 141 997	2 140 738	3 141 997	2 140 738
Sales of gas	554 248	369 694	554 248	369 694
Tariff income	19 423	22 891	19 423	22 891
Total petroleum sales	3 715 668	2 533 323	3 715 668	2 533 323
Impact from change in over/underlift balances of liquids	-4 197	42 331	-4 197	42 331
Total petroleum revenues	3 711 472	2 575 654	3 711 472	2 575 654

Breakdown of produced volumes (barrels of oil equivalent) (unaudited)	Group 2018	Group 2017	Parent 2018	Parent 2017
Liquids	44 732 273	39 634 824	44 732 273	39 634 824
Gas	12 082 972	11 036 406	12 082 972	11 036 406
Total produced volumes	56 815 246	50 671 230	56 815 246	50 671 230

Other income (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Realized gain/loss (-) on oil derivatives	-16 242	-7 440	-16 242	-7 440
Unrealized gain/loss (-) on oil derivatives	24 944	-6 510	24 944	-6 510
Other income*	29 898	1 230	29 898	1 230
Total other operating income	38 600	-12 721	38 600	-12 721

* For 2018 the amount is mainly related to a non-recurring tariff compensation.

Refer to note 21 and 27 for further details regarding commodity derivatives.

Note 7 Remuneration and guidelines for remuneration of senior executives and the Board of Directors, and total payroll expenses

Breakdown of payroll expenses (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Payroll expenses	275 220	252 889	275 220	252 889
Pension	27 460	20 469	27 460	20 469
Social security tax	42 945	38 692	42 945	38 692
Other personnel costs	4 950	4 280	4 950	4 280
Total payroll expenses	350 575	316 330	350 575	316 330

Employee share program

The company has an annual share purchase program for all employees, including senior executives. The shares in the program are offered at a 20 per cent discount and are subject to a three-year lock-up during which employees are not allowed to sell the shares. In connection with the share purchase program, all employees are also offered an interest free loan of 60% of the basic amount in the National Insurance scheme ("G"), to be repaid within one year. In total, employees subscribed for approximately USD 13.2 million in 2018, up from USD 11.3 million in 2017.

Number of full time equivalents employed during the year	Group 2018	Group 2017	Parent 2018	Parent 2017
Europe	1 493	1 341	1 493	1 341
Total	1 493	1 341	1 493	1 341

Remuneration of senior executives in 2018* (USD 1 000)	Salary	Bonus**	Payments in kind	Other	Total remuneration	Pension costs	Total number of shares***	Owning interest
Karl Johnny Hersvik (Chief Executive Officer) [1]	783	1 187	2	1	1 973	21	3 577	0.0 %
Øyvind Bratsberg (Special Advisor)	453	177	2	4	635	22	54 290	0.0 %
Alexander Krane (Chief Financial Officer)	438	172	9	-	619	21	17 021	0.0 %
Gro G. Haatvedt (SVP Exploration) [2]	476	-	1	5	483	77	10 832	0.0 %
Olav Henriksen (SVP Projects)	481	291	2	-	774	102	-	-
Per Harald Kongelf (SVP Improvement)	413	171	2	-	586	23	-	-
Tommy Sigmundstad (SVP D&W)	370	155	4	12	541	21	7 528	0.0 %
Ole Johan Molvig (SVP Reservoir Development)	376	155	2	-	533	21	6 485	0.0 %
Jorunn Kvåle (SVP HSSE)	284	116	2	18	420	23	-	-
Eldar Larsen (SVP Operations) [3]	388	158	2	24	572	22	1 858	0.0 %
Evy Glørstad-Clark (SVP Exploration) [4]	300	103	2	2	406	22	5 866	0.0 %
Svein Jakob Liknes (SVP Operations) [5]	353	105	6	-	464	21	-	-
Total remuneration of senior executives in 2018	5 116	2 789	34	65	8 004	396	107 457	0.0 %

[1] Bonus includes accrued LTI commitments
[2] SVP Exploration until 31.07.2018
[3] SVP Operations until 06.05.2018
[4] SVP Exploration since 01.08.2018
[5] Acting SVP Operations since 07.05.2018

* All remuneration to senior executives is paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.1338.

** Numbers represent actual bonus earned in 2018. From the total amount in this column, USD 671 thousand relates to LTI program.

*** These shares have been purchased by the individuals and are not part of their remuneration. The numbers include shares held in companies where the senior executives have a controlling interest.

Remuneration of senior executives in 2017* (USD 1 000)	Salary	Bonus**	Payments in kind	Other	Total remuneration	Pension costs	Total number of shares***	Owning interest
Karl Johnny Hersvik (Chief Executive Officer) [1]	721	1 183	2	11	1 917	19	1 416	0.0 %
Øyvind Bratsberg (Special Advisor) [1]	427	331	2	4	763	19	53 848	0.0 %
Alexander Krane (Chief Financial Officer) [1]	412	297	6	-	716	19	16 248	0.0 %
Gro G. Haatvedt (SVP Exploration) [1,2]	442	446	2	6	896	76	10 832	0.0 %
Olav Henriksen (SVP Projects) [1]	447	453	2	-	902	84	-	-
Per Harald Kongelf (SVP Improvement)	365	186	2	-	553	19	-	-
Tommy Sigmundstad (SVP D&W)	323	165	2	-	490	19	-	-
Ole Johan Molvig (SVP Reservoir Development)	341	165	2	19	526	19	3 894	0.0 %
Jorunn Kvåle (SVP HSSE)	266	128	2	18	414	19	-	-
Eldar Larsen (SVP Operations) [2]	367	174	2	25	568	19	1 416	0.0 %
Total remuneration of senior executives in 2017	4 113	3 526	21	84	7 745	316	87 654	0.0 %

[1] Bonus includes estimated LTI commitments during 2017.
[2] A loan in connection with the employee share program has been provided and will be repaid during 2018.

* All remuneration to senior executives is paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.263.

** Numbers represent actual bonus earned in 2017. From the total amount in this column, USD 1 171 thousand relates to LTI program.

*** These shares have been purchased by the individuals and are not part of their remuneration.

The tables below include regular fees to the Board and fees for participation in the Board's subcommittees. The fees to the nomination committee are also included. Fees to Board members employed in Aker ASA or BP plc groups will be paid to the companies, not to the Board member in person. Some Board members have shares in the company. The table also includes the number of shares and owning interest in Aker BP ASA held directly or indirectly through related parties. Indirect ownership through other companies is included as a whole where the individual owns 50 per cent or more of such companies.

Fees in 2018* Name	Comments	Fee (USD 1 000)	Total number of shares	Owning interest
Øyvind Eriksen	Chairman of the Board from 11 March 2016. Chairman of the Compensation committee.	108	-	-
Anne Marie Cannon	Deputy Chair from 17 April 2013. Member of the Audit & Risk committee.	68	6 308	0.0 %
Bernard Looney	Board member from 30 September 2016.	-	-	-
Kjell Inge Røkke [1)]	Board member from 17 April 2013.	47	-	-
Trond Brandsrud	Board member from 11 March 2016. Chairman of the Audit & Risk committee from 28 April 2016.	71	-	-
Kate Thomson	Board member from 30 September 2016. Member of the Audit & Risk committee from 4 October 2016.	-	-	-
Gro Kielland	Board member from 20 March 2014. Member of the Compensation committee.	61	-	-
Terje Solheim	Employee representative from 20 March 2014. Member of the Compensation committee.	28	1 150	0.0 %
Lone Margrethe Olstad	Employee representative from 11 March 2016.	19	-	-
Ørjan Holstad	Employee representative from 1 November 2017.	28	1 789	0.0 %
Murray Auchincloss	Deputy board member from 1 April 2017.	-	-	-
Nina Aas	Deputy employee representative from 30 August 2018.	1	2 288	0.0 %
Oddbjørn Aune	Deputy employee representative from 30 August 2018.	1	4 068	0.0 %
Hilde K.Breivik	Deputy employee representative from 30 August 2018.	1	156	0.0 %
Arild Støren Frick	Chairman of the Nomination committee from 13 April 2015.	4	-	-
Finn Haugan	Member of the Nomination committee.	4	-	-
Hilde Myrberg	Member of the Nomination committee.	4	-	-
Ingar Haugeberg	Employee representative from 30 August 2018.	8	970	0.0 %
Anette Hoel Helgesen	Employee representative from 30 August 2018.	8	-	-
Members until 30 August 2018				
Bjørn Thore Ribesen	Employee representative from 11 March 2016 to 30 August 2018.	18	24 462	0.0 %
Kristin Gjertsen (2.deputy)	Deputy employee representative from 11 March 2016 to 30 August 2018.	3	-	-
Ifor Roberts (3.deputy)	Deputy employee representative from 11 March 2016 to 30 August 2018.	3	12 345	0.0 %
Martine Midtsand Hovland	Deputy employee representative from November 2017 to 30 August 2018.	3	-	-
Total		492	53 536	0.0 %

* Fee to board members are paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.1338.

Fees in 2017*

Name	Comments	Fee (USD 1 000)	Total number of shares	Owning interest
Øyvind Eriksen	Chairman of the Board from 11 March 2016. Chairman of the Compensation committee.	106	-	-
Anne Marie Cannon	Deputy Chair from 17 April 2013. Member of the Audit & Risk committee.	78	6 308	0.0 %
Bernard Looney	Board member from 30 September 2016.	-	-	-
Kjell Inge Røkke [1]	Board member from 17 April 2013.	46	-	-
Trond Brandsrud	Board member from 11 March 2016. Chairman of the Audit & Risk committee from 28 April 2016.	47	-	-
Kate Thomson	Board member from 30 September 2016. Member of the Audit & Risk committee from 4 October 2016.	-	-	-
Gro Kielland	Board member from 20 March 2014. Member of the Compensation committee.	48	-	-
Terje Solheim	Employee representative from 20 March 2014. Member of the Compensation committee.	28	1 906	0.0 %
Lone Margrethe Olstad	Employee representative from 11 March 2016.	24	-	-
Bjørn Thore Ribesen	Employee representative from 11 March 2016.	24	22 747	0.0 %
Ørjan Holstad	Employee representative from 1 November 2017.	3	1 062	0.0 %
Emil Brustad-Nilsen	Deputy board member from 11 March 2016.	11	-	-
Murray Auchincloss	Deputy board member from 1 April 2017.	-	-	-
Kristin Gjertsen (2.deputy)	Deputy employee representative from 11 March 2016.	8	-	-
Ifor Roberts (3.deputy)	Deputy employee representative from 11 March 2016.	5	10 644	0.0 %
Martine Midtsand Hovland	Deputy employee representative from 1 November 2017.	-	1 713	0.0 %
Arild Støren Frick	Chairman of the Nomination committee from 13 April 2015.	4	-	-
Finn Haugan	Member of the Nomination committee.	6	-	-
Hilde Myrberg	Member of the Nomination committee.	6	-	-
Members until 30 June 2017				
Aage Ertsgaard (1.deputy)	Deputy employee representative from 11 March 2016 to 30 June 2017.	2	6 508	0.0 %
Total		447	50 888	0.0 %

[1] Mr. Røkke owns and controls The Resource Group AS, which owns 68.2 per cent of Aker ASA, which through a subsidiary owns 40.0 per cent of Aker BP.

* Fee to board members are paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.263.

Guidelines and adherence to the guidelines in 2018

In 2018, the company's remuneration policy has been in accordance with the guidelines described in the Board of Directors' Report for 2017 and submitted to the annual general meeting for an advisory vote in April 2018.

Guidelines for 2019

The Board has established guidelines for 2019 for salaries and other remuneration to the Chief Executive Officer and other senior executives. The guidelines will be reviewed at the company's annual general meeting in 2019.

Senior executives receive a basic salary, adjusted annually. The company's senior executives participate in the general arrangements applicable to all the company's employees as regards bonus programme (see below), pension plans and other payments in kind such as free internet connection at home and subsidized fitness centre fees. In special cases, the company may offer other benefits in order to recruit personnel, including to compensate for bonus rights earned in previous employment.

For bonus arrangements for executive management, reference is made to the section Executive Remuneration in the Board of Directors report on corporate governance. Estimated amount incurred in 2018 for the different bonus arrangements, including the three year incentive program, is included in the bonus column in the table above.

Adjustment of the CEO's base salary is decided by the Board. Adjustment of the base salaries for other senior executives is decided by the CEO within the wage settlement framework adopted by the Board.

It is up to the Board to decide whether to pay bonuses, based on the previous year’s performance. For 2018, the bonus will be disbursed in Q1 2019.

Note 8 Auditors fee

	Group		Parent	
(USD 1 000)	2018	2017	2018	2017
Fees for statutory audit services - KPMG (excluding VAT)	429	618	429	618
Fees for other attestations - KPMG (excluding VAT)	132	349	132	349
Total auditor's fees	**561**	**967**	**561**	**967**

Note 9 Financial items

	Group		Parent	
(USD 1 000)	2018	2017	2018	2017
Total interest income	**25 976**	**7 716**	**19 114**	**7 012**
Realized gains on derivatives	141 823	18 428	141 823	18 428
Change in fair value of derivatives	-	40 971	-	40 971
Net currency gains	-	16 107	43 592	16 107
Other financial income*	-	-	-	40 894
Total other financial income	**141 823**	**75 507**	**185 415**	**116 401**
Interest expenses	200 524	156 704	200 524	176 248
Capitalized interest cost, development projects	-110 213	-89 977	-110 213	-89 977
Amortized loan costs	29 722	36 900	29 722	36 900
Total interest expenses	**120 033**	**103 627**	**120 033**	**123 171**
Net currency loss/gain (-) before reclassification from OCI	-43 592	-	-	-
Reclassification from OCI**	47 504	-	-	-
Realised loss on derivatives	45 993	9 331	45 993	9 331
Change in fair value of derivatives	36 503	-	36 503	-
Accretion expenses	128 737	129 619	128 737	129 619
Other financial expenses*	3 128	36 746	70 456	37 102
Total other financial expenses	**218 272**	**175 696**	**281 689**	**176 052**
Net financial items	**-170 505**	**-196 100**	**-197 192**	**-175 810**

* The parent company number includes a group continuity adjustment, as well as other adjustments to the value of shares in subsidiaries.

** The reclassification from OCI relates to the refund of tax losses in Aker BP AS (previously Hess Norge AS), and the subsequent liquidation of Aker BP AS. The reclassification reflects the USD/NOK currency movement from the acquisition of Hess Norge AS at 22 December 2017 to the tax refund and liquidation of Aker BP AS on 28 November 2018.

The rate (weighted average interest rate) used to determine the amount of borrowing cost eligible for capitalisation in 2018 is 6.52 per cent. The corresponding rate for 2017 was 8.06 per cent.

Note 10 Taxes

	Group		Parent	
Breakdown of the current year's tax income (-)/tax expense (+) (USD 1 000)	2018	2017	2018	2017
Current year tax payable	803 396	332 092	801 818	327 238
Prior periods' adjustments to current tax	32 069	4 516	32 069	4 516
Current tax income (-)/expense (+)	**835 465**	**336 608**	**833 886**	**331 754**
Current year deferred tax	526 933	202 715	526 933	202 715
Prior periods' adjustments to deferred tax	-33 912	-2 982	-33 912	-2 982
Deferred tax income (-)/expense (+)	**493 021**	**199 733**	**493 021**	**199 733**
Net tax income (-)/tax expense (+)	**1 328 486**	**536 340**	**1 326 907**	**531 487**
Effective tax rate in %	**74%**	**66 %**	**75%**	**64 %**

Reconciliation of tax income (-)/tax expense (+) (USD 1 000)	Tax rate	Group 2018	Group 2017	Parent 2018	Parent 2017
78% tax rate on profit before tax	78%	1 407 829	632 680	1 387 013	648 524
Tax effect on uplift	55%	-130 767	-123 057	-130 767	-123 057
Change in tax rates		-2 047	-1 894	-2 047	-1 894
Permanent difference on impairment	78%	-	22 813	-	22 813
Tax effect on OCI reclassification*	78%	37 053	-	-	-
Foreign currency translation of NOK monetary items	78%	-34 002	-12 955	-34 002	-12 955
Foreign currency translation of USD monetary items	78%	-111 806	120 113	-111 806	120 113
Tax effect of financial and other 23%/24% items	55%	50 578	-19 592	50 578	-8 671
Revaluation of tax balances**	78%	113 147	-84 676	113 147	-84 676
Other permanent differences and prior period adjustments	78%	-1 498	2 908	54 792	-28 710
Total taxes (+)/tax income (-)		1 328 486	536 340	1 326 907	531 487

* Refer to note 9. This amount is not tax deductible, and so represents a permanent difference in the effective tax rate reconciliation

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

The tax rate for general corporation tax changed from 23 to 22 per cent from 1 January 2019. The rate for special tax changed from the same date from 55 to 56 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.

Breakdown of tax effect of temporary differences and tax losses carry forward (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Tangible fixed assets	-2 401 716	-2 339 675	-2 401 716	-2 339 675
Capitalized exploration cost	-333 402	-285 025	-333 402	-285 025
Other intangible assets	-1 100 480	-1 151 969	-1 100 480	-1 151 969
Abandonment provision	1 986 262	2 354 228	1 986 262	2 354 228
Financial instruments	4 095	1 597	4 095	1 597
Other provisions	45 042	113 696	45 042	113 696
Total deferred tax liability (-)/deferred tax asset (+)	-1 800 199	-1 307 148	-1 800 199	-1 307 148

Reconciliation of change in deferred tax (-)/deferred tax asset (+) (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Deferred tax (-)/ deferred tax assets (+) as of 1.1	-1 307 148	-1 045 542	-1 307 148	-1 045 542
Current year deferred tax in Income statement	-526 933	-202 715	-526 933	-202 715
Deferred tax related to acquisitions/sales	-	-61 877	-	-61 877
Prior period adjustments	33 912	2 982	33 912	2 982
Deferred tax charged to OCI and equity	-30	5	-30	5
Total deferred tax liability (-)/deferred tax asset (+)	-1 800 199	-1 307 148	-1 800 199	-1 307 148

Reconciliation of change in tax receivable (+)/tax payable (-) (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Tax receivable (+)/tax payable (-) at 1.1	1 234 850	307 977	-351 156	46 783
Current year tax in Income statement	-803 396	-332 092	-801 818	-327 238
Tax receivable (+)/tax payable (-) related to acquisitions/sales	4 387	1 523 512	2 809	-35 062
Tax payment (+)/tax refund (-)	-907 312	-303 589	606 082	-39 798
Prior period adjustments and change in estimate of uncertain tax positions	-30 269	9 502	-30 269	9 502
Revaluation of tax payable	-39 119	29 540	33 492	-5 343
Tax receivable (+)/tax payable (-)	-540 860	1 234 850	-540 860	-351 156
Tax receivable	11 082	1 586 006	11 082	-
Tax payable	-551 942	-351 156	-551 942	-351 156

Note 11 Earnings per share

Earnings per share is calculated by dividing the year's profit attributable to ordinary equity holders of the parent entity, which was USD 476 million (USD 275 million in 2017) by the year's weighted average number of outstanding ordinary shares, which was 360.1 million (340.2 million in 2017). There are no option schemes or convertible bonds in the company. This means that there is no difference between the ordinary and diluted earnings per share.

	Group	
(USD 1 000)	2018	2017
Profit for the year attributable to ordinary equity holders of the parent entity	476 423	274 787
The year's average number of ordinary shares (in thousands)	360 114	340 189
Earnings per share in USD	1.32	0.81

Note 12 Tangible fixed assets and intangible assets

TANGIBLE FIXED ASSETS - GROUP AND PARENT

(USD 1 000)	Assets under development	Production facilities including wells	Fixtures and fittings, office machinery	Total
Book value 31.12.2016	907 108	3 501 908	32 779	4 441 796
Acquisition cost 31.12.2016	908 674	4 950 566	56 137	5 915 377
Acquisition of Hess Norge AS	-	1 076 337	-	1 076 337
Additions*	794 809	-129 338	43 401	708 873
Disposals**	33 329	88 913	1 531	123 773
Reclassification	-189 466	249 149	6 339	66 021
Acquisition cost 31.12.2017	1 480 689	6 057 801	104 346	7 642 835
Accumulated depreciation and impairments 31.12.2016	1 566	1 448 659	23 357	1 473 582
Depreciation	-	622 179	13 384	635 563
Impairment	-6	21 111	128	21 232
Retirement/disposals/transfer depreciations	-1 560	-66 944	-1 531	-70 035
Accumulated depreciation and impairments 31.12.2017	-	2 025 004	35 338	2 060 342
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*	1 011 222	-172 615	22 662	861 269
Reclassification	-208 309	201 176	8 053	921
Acquisition cost 31.12.2018	2 283 602	6 086 362	135 061	8 505 025
Accumulated depreciation and impairments 31.12.2017	-	2 025 004	35 338	2 060 342
Depreciation	-	656 697	22 054	678 751
Impairment	-	19 657	-	19 657
Accumulated depreciation and impairments 31.12.2018	-	2 701 357	57 392	2 758 750
Book value 31.12.2018	2 283 602	3 385 005	77 669	5 746 275

* The negative addition is mainly caused by decreased abandonment provision during the year, see Note 20.

** The disposal is mainly related to the sale of 10 per cent share in Valhall/Hod during 2017.

Capitalized exploration expenditures are reclassified to "Assets 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. Assets 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.

See note 13 for information regarding impairment charges.

INTANGIBLE ASSETS - GROUP AND PARENT

(USD 1 000)	Other intangible assets Licences etc.	Software	Total	Exploration wells	Goodwill
Book value 31.12.2016	1 332 534	279	1 332 813	395 260	1 846 971
Acquisition cost 31.12.2016	1 575 203	7 501	1 582 705	395 260	2 720 835
Acquisition of Hess Norge AS	507 640	-	507 640	-	181 930
Additions	156	-	156	111 569	-
Disposals/expensed dry wells*	149 747	-	149 747	75 401	163 791
Reclassification	-11	-	-11	-66 011	-
Acquisition cost 31.12.2017	1 933 241	7 501	1 940 742	365 417	2 738 973
Accumulated depreciation and impairments 31.12.2016	242 670	7 223	249 892	-	873 864
Depreciation	90 863	245	91 107	-	-
Impairment	1 956	-	1 956	-	29 161
Retirement/disposals/transfer depreciations	-19 252	-	-19 252	-	-24 177
Accumulated depreciation and impairments 31.12.2017	316 236	7 467	323 703	-	878 847
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	463 049	-	463 049	128 795	-
Disposals/expensed dry wells	-	-	-	65 852	-
Reclassification	-	-	-	-921	-
Acquisition cost 31.12.2018	2 396 290	7 501	2 403 791	427 439	2 738 973
Accumulated depreciation and impairments 31.12.2017	316 236	7 467	323 703	-	878 847
Depreciation	73 653	34	73 686	-	-
Impairment	516	-	516	-	-
Accumulated depreciation and impairments 31.12.2018	390 404	7 501	397 906	-	878 847
Book value 31.12.2018	2 005 885	-	2 005 885	427 439	1 860 126

* The disposal is mainly related to the sale of 10 per cent share in Valhall/Hod during 2017.

Licenses related to fields in production are depreciated using the Unit of Production method. Software is depreciated over its useful life (three years, using a straight-line method).

Depreciation in the Income statement (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Depreciation of tangible fixed assets	678 751	635 563	678 751	635 563
Depreciation of intangible assets	73 686	91 107	73 686	91 107
Total depreciation in the Income statement	752 437	726 670	752 437	726 670

Impairment in the Income statement (USD 1 000)	Group 2018	Group 2017	Parent 2018	Parent 2017
Impairment/reversal of tangible fixed assets	19 657	21 232	19 657	21 232
Impairment/reversal of intangible assets	516	1 956	516	1 956
Impairment of goodwill	-	29 161	-	29 161
Total impairment in the Income statement	20 172	52 349	20 172	52 349

See note 13 for information regarding impairment charges.

Note 13 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. In 2018, two categories of impairment tests have been performed:

- Impairment test of fixed assets and related intangible assets, other than goodwill
- Impairment test of goodwill

Impairment is recognized when the book value of an asset or a cash-generating unit, including associated goodwill, exceeds the recoverable amount. The recoverable amount is the higher of the asset's fair value less cost to sell and value in use. For assets and goodwill in the Group prior to the acquisition of BP Norge AS, the impairment testing has been based on value in use, consistent with the impairment testing prior to the acquisition of BP Norge AS. For assets and goodwill recognized in relation to the acquisition of BP Norge AS and Hess Norge AS, the impairment testing has been based on fair value (level 3 in fair value hierarchy). For both value in use and fair value, the impairment testing is performed based on discounted cash flows. The expected future cash flow is discounted to the net present value by applying a discount rate after tax that reflects the current market valuation of the time value of money, and the specific risk related to the asset. The discount rate is derived from the weighted average cost of capital (WACC) for a market participant. Cash flows are projected for the estimated lifetime of the fields, which may exceed periods greater than five years. If not specifically stated otherwise, the same assumptions have been applied for value in use and fair value testing.

For producing licenses and licenses in the development phase, recoverable amount is estimated based on discounted future after tax cash flows. Below is an overview of the key assumptions applied for impairment testing purposes as of 31 December 2018.

Oil and gas prices

Future price level is a key assumption and has significant impact on the net present value. Forecasted oil and gas prices are based on management's estimates and available market data. Information about market prices in the near future can be derived from the futures contract market. The information about future prices is less reliable on a long-term basis, as there are fewer observable market transactions going forward. In the impairment test, the oil price is therefore based on the forward curve from the beginning of 2019 to the end of 2021. From 2022, the oil price is based on the company's long-term price assumptions. Long term oil price assumption is unchanged from year end 2017.

The nominal oil prices applied in impairment test are as follows:

Year	USD/BOE
2019	56.0
2020	57.1
2021	58.1
From 2022 (in real terms)	65.0

The nominal gas prices applied in impairment test are as follows:

Year	GBP/therm
2019	0.58
2020	0.54
2021	0.51
From 2022 (in real terms)	0.49

Oil and gas reserves

Future cash flows are calculated on the basis of expected production profiles and estimated proven and probable remaining reserves. The recoverable amount is sensitive to changes in reserves. For more information about the determination of the reserves, reference is made to note 1, section 1.3, and to note 29.

Future expenditure

Future capex, opex and abandonment cost are calculated based on the expected production profiles and the best estimate of the related cost.

Discount rate

The discount rate is derived from the company's weighted average cost of capital ("WACC"). The capital structure considered in the WACC calculation is derived from the capital structures of an identified peer group and market participants with consideration given to optimal structures. The cost of equity is derived from the expected return on investment by the company's investors. The cost of debt is based on the interest-bearing borrowings on debt specific to the assets acquired. The beta factors are evaluated annually based on publicly available market data about the identified peer group.

For value in use testing, the post tax nominal discount rate used is 7.9 per cent, which is a change from 7.5 per cent applied in previous quarters in 2018 and year end 2017. For fair value testing, the discount rate used is 10.0 per cent (unchanged from previous quarters in 2018 and from year end 2017). The difference between the discount rate applied for fair value and value in use testing reflects the additional risk in in the cash flows used in fair value testing.

Currency rates

Year	USD/NOK
2019	8.58
2020	8.48
2021	8.42
From 2022	7.50

Long term currency rate at year end 2017 was 7.75 USD/NOK.

Inflation

The long-term inflation rate is assumed to be 2.0 per cent, which is a change from 2.5 per cent applied at year end 2017.

Impairment testing of assets other than goodwill

The impairment test of assets other than goodwill has been performed prior to the quarterly goodwill impairment test. If these assets are found to be impaired, their carrying value will be written down before the impairment test of goodwill. The carrying value of the assets is the sum of tangible assets and intangible assets as of the assessment date.

Below is an overview of the impairment charge and the carrying value per cash generating unit where impairment has been recognized in 2018:

	Impairment charged/reversal		Recoverable amount/
Cash generating unit (USD 1 000)	Intangible	Tangible	carrying value at 31.12.18
Gina Krog	-	25 202	97 535
Other CGU's	516	-5 546	-
Total	516	19 657	97 535

The reversal of impairment and impairment charge for other CGU's with no carrying value is related to changes in the ARO liability.

Impairment testing of technical goodwill

Technical goodwill has been allocated to individual CGUs for the purpose of impairment testing. The residual goodwill is allocated to group of CGUs including all fields acquired together with all existing Aker BP's fields, as this mainly relates to tax and workforce synergies and the ability to capture synergies from managing a portfolio of both acquired and existing fields on the NCS.

The carrying value of the CGUs consists of the carrying values of the oilfield assets plus associated technical goodwill. In the impairment test performed, carrying value is adjusted by the remaining part of deferred tax from which the technical goodwill arose, to avoid an immediate impairment of all technical goodwill. When deferred tax liabilities from the acquisitions decreases as a result of depreciation, more goodwill is as such exposed for impairment. This may lead to future impairment charges even though other assumptions remain stable.

We have tested the Alvheim, Valhall/Hod, Skarv/Ærfugl and Ula/Tambar CGUs, and no impairment charge of technical goodwill has been recognised as a result.

Sensitivity analysis

The table below shows how the impairment of technical goodwill would be affected by changes in the various assumptions, given that the remaining assumptions are constant. The only impacted CGU is Ula/Tambar.

		Change in goodwill impairment after	
Assumption (USD 1 000)	Change	Increase in assumption	Decrease in assumption
Oil and gas price	+/- 20%	-	135 422
Production profiles (reserves)	+/- 5%	-	34 854
Discount rate	+/- 1% point	20 081	-
Currency rate USD/NOK	+/- 1.0 NOK	-	56 760
Inflation	+/- 1% point	-	33 628

Impairment testing of residual goodwill

As mentioned above, residual goodwill is allocated across all CGUs for impairment testing. The combined recoverable amount exceeds the carrying amount by a substantial margin. Based on this, no impairment of residual goodwill has been recognized.

Impairment testing in 2017

In 2017, the impairment charge was in all material respect related to technical goodwill from acquisitions and impairment of tangible fixed assets. The methodology for impairment testing was the same as in 2018 as described in this Note.

The following assumptions were applied for the impairment testing at year end 2017:
- discount rate of 7.5 per cent nominal after tax (value in use) and 10.0 per cent nominal after tax (fair value)
- a long-term inflation of 2.5 per cent
- a long-term exchange rate of NOK/USD 7.75 (forward curve first three years)
- a long-term oil price assumption of 65 USD/barrel, using forward curve first three years

Summary of impairment/reversal of impairments

The following impairments/(reversals) have been recorded:

	Group and parent	
(USD 1 000)	2018	2017
Impairment of other intangible assets/licence rights	516	1 956
Impairment of tangible fixed assets	19 657	21 232
Impairment of technical goodwill	-	29 161
Total impairments	20 172	52 349

Note 14 Accounts receivable

The company's customers are mainly large, financially sound oil companies. Accounts receivable consist of receivables related to the sale of oil and gas.

	Group		Parent	
(USD 1 000)	31.12.2018	31.12.2017	31.12.2018	31.12.2017
Receivables related to the sale of petroleum	162 798	99 752	162 798	99 752
Total accounts receivable	162 798	99 752	162 798	99 752

Age distribution of accounts receivable as of 31 December for the group was as follows:

Year (USD 1 000)	Total	Not due	<30d	30-90d	>90d
2018	162 798	162 798	-	-	-
2017	99 752	99 752	-	-	-

Note 15 Other short-term receivables

	Group		Parent	
(USD 1 000)	31.12.2018	31.12.2017	31.12.2018	31.12.2017
Prepayments	64 004	59 100	64 004	59 100
VAT receivable	8 871	10 856	8 871	10 856
Underlift of petroleum	122 713	118 012	122 713	118 012
Accrued income from sale of petroleum products	52 825	105 670	52 825	105 670
Other receivables, mainly from licenses	111 781	241 879	111 781	241 879
Total other short-term receivables	360 194	535 518	360 194	535 518

Note 16 Other non-current assets

(USD 1 000)	Group 31.12.2018	Group 31.12.2017	Parent 31.12.2018	Parent 31.12.2017
Shares in Alvheim AS	10	10	10	10
Shares in Det norske oljeselskap AS	1 021	1 021	1 021	1 021
Shares in Sandvika Fjellstue AS	1 814	1 814	1 814	1 814
Shares in Aker BP AS	-	-	-	1 586 006
Investment in subsidiaries	2 845	2 845	2 845	1 588 851
Tenancy deposit	1 934	2 027	1 934	2 027
Other non-current assets	5 609	3 526	5 609	3 526
Total other non-current assets	10 388	8 398	10 388	1 594 404

Alvheim AS, Det norske oljeselskap AS (previously Marathon Oil Norge AS) and Sandvika Fjellstue AS have been deemed immaterial for consolidation purposes. For more information regarding shares in subsidiaries, see Note 2.

The acquisition of Hess Norge AS (renamed to Aker BP AS post transaction) was completed at 22 December 2017 and the company was liquidated during Q4 2018.

Note 17 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 31.12.2018	Group 31.12.2017	Parent 31.12.2018	Parent 31.12.2017
Bank deposits	44 944	231 506	44 944	231 506
Restricted funds (tax withholdings)*	-	998	-	998
Cash and cash equivalents	44 944	232 504	44 944	232 504
Unused reserve-based lending facility (see note 23)	3 050 000	2 670 000	3 050 000	2 670 000

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

Note 18 Share capital and shareholders

(USD 1 000)	Parent 31.12.2018	Parent 31.12.2017
Share capital	57 056	57 056
Total number of shares (in 1 000)	360 114	360 114
Nominal value per share in NOK	1.00	1.00

There is only one single class of shares in the company and all shares carry a single voting right.

Overview of the 20 largest shareholders registered as of 31 December 2018	No. of shares (in 1 000)	Owning interest
AKER CAPITAL AS	144 049	40.00%
BP Exploration Operating Company Ltd	108 021	30.00%
FOLKETRYGDFONDET	13 981	3.88%
VERDIPAPIRFONDET DNB NORGE (IV)	3 068	0.85%
CLEARSTREAM BANKING S.A.*	2 807	0.78%
State Street Bank and Trust Comp*	2 637	0.73%
State Street Bank and Trust Comp*	1 846	0.51%
JPMorgan Chase Bank, N.A., London*	1 646	0.46%
Brown Brothers Harriman (Lux.) SCA*	1 561	0.43%
State Street Bank and Trust Comp*	1 345	0.37%
Santander Securities Services, S.A*	1 337	0.37%
State Street Bank and Trust Comp*	1 266	0.35%
State Street Bank and Trust Comp*	1 146	0.32%
VERDIPAPIRFONDET ALFRED BERG GAMBA	1 140	0.32%
KLP AKSJENORGE	1 110	0.31%
JPMorgan Chase Bank, N.A., London*	1 098	0.30%
CACEIS Bank*	1 074	0.30%
The Bank of New York Mellon SA/NV*	1 074	0.30%
DANSKE INVEST NORSKE INSTIT. II.	1 050	0.29%
JP MORGAN SECURITIES PLC	1 023	0.28%
OTHER	67 834	18.84%
Total	360 114	100.00%

* Nominee accounts

Note 19 Bonds

	Group		Parent	
(USD 1 000)	31.12.2018	31.12.2017	31.12.2018	31.12.2017
DETNOR02 Senior unsecured bond *	223 839	230 375	223 839	230 375
AKERBP – Senior Notes 2017 (17/22) **	393 301	391 664	393 301	391 664
AKERBP – Senior Notes 2017 (18/25) ***	493 349	-	493 349	-
Long-term bonds	1 110 488	622 039	1 110 488	622 039

* 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 23.

** 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.

*** 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 20 Provision for abandonment liabilities

	Group and parent	
(USD 1 000)	31.12.2018	31.12.2017
Provisions as of 1 January	3 043 884	2 156 921
Abandonment liability from acquisitions	-	1 315 181
Change in abandonment liability due to asset sales	-	-207 516
Incurred cost removal	-201 227	-74 005
Accretion expense - present value calculation	128 737	129 619
Changed net present value from changed discount rate	-277 081	511 330
Change in estimates and incurred liabilities on new drilling and installations	-141 721	-787 646
Total provision for abandonment liabilities	2 552 592	3 043 884
Break down of the provision to short-term and long-term liabilities		
Short-term	105 035	268 262
Long-term	2 447 558	2 775 622
Total provision for abandonment liabilities	2 552 592	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 2.0 per cent and a nominal discount rate before tax of between 4.46 per cent and 5.01 per cent. For 2017 the inflation rate was 2.5 per cent and the discount rate was between 3.44 per cent and 4.42 per cent. In 2018 the credit margin included in the discount rate is 2.00 per cent. For 2017 the credit margin was 1.68 per cent.

Note 21 Derivatives

	Group and parent	
(USD 1 000)	31.12.2018	31.12.2017
Unrealized gain currency contracts	-	12 564
Long-term derivatives included in assets	-	12 564
Unrealized gain commodity derivatives	17 253	-
Unrealized gain currency contracts	-	2 585
Short-term derivatives included in assets	17 253	2 585
Total derivatives included in assets	17 253	15 149
Unrealized losses interest rate swaps	26 275	13 705
Long-term derivatives included in liabilities	26 275	13 705
Unrealized losses currency contracts	8 783	-
Unrealized losses commodity derivatives	-	7 691
Short-term derivatives included in liabilities	8 783	7 691
Total derivatives included in liabilities	35 058	21 396

The group has different types of economic hedging instruments. The 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. In the Income statement, impacts from commodity derivatives are presented as other income, while impacts from other derivatives are presented as financial items.

Note 22 Provisions for other liabilities

Breakdown of provisions for other liabilities (USD 1 000)	Group and parent 31.12.2018	31.12.2017
Fair value of contracts assumed in acquisitions*	106 040	149 031
Other long term liabilities	1 480	3 387
Total provisions for other liabilities	107 519	152 418

* The negative contract values are mainly related to rig contracts entered into by the acquirees, which were different 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 23 Other interest-bearing debt

(USD 1 000)	Group and parent 31.12.2018	31.12.2017
Reserve-based lending facility	907 954	1 270 556
Long-term interest-bearing debt	907 954	1 270 556
Bridge facility	-	1 496 374
Short-term interest-bearing debt	-	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 terms of the facility included a mandatory repayment clause triggered by the refund of tax losses in Hess Norge. The refund took place in November 2018 and the facility was repaid and cancelled at the same time.

Note 24 Other current liabilities

	Group		Parent	
Breakdown of other current liabilities (USD 1 000)	31.12.2018	31.12.2017	31.12.2018	31.12.2018
Current liabilities related to overcall in licences	22 779	81 223	22 779	81 223
Share of other current liabilities in licences	309 260	409 387	309 260	409 387
Overlift of petroleum	17 021	9 610	17 021	9 610
Fair value of contracts assumed in acquisitions*	42 998	62 097	42 998	62 097
Other current liabilities**	198 801	141 880	198 801	141 880
Total other current liabilities	590 860	704 197	590 860	704 197

* The negative contract values are mainly related to rig contracts entered into by the acquirees, which were different 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.

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

Note 25 Lease agreements, capital commitments, contractual obligations, guarantees and contingent liabilities

The company has entered into different operating leases for rig contracts, other license related commitments and office premises. The leases do not contain any restrictions on the company's dividend policy or financing. The company has not had any material contingent rent for the years presented below. To the extent the lease has been approved and committed by the partners in the relevant Aker BP operated licenses, the committments disclosed represent Aker BP share only.

Significant lease agreements

On behalf of the partners in Ivar Aasen, the company signed an agreement in 2013 with Maersk Drilling for the delivery of a jack-up rig for the development project on the Ivar Aasen field. The rig has drilled production wells on Ivar Aasen, but has been partly subleased to other licenses for the remaining lease period. The initial contract period expires in December 2019, with an additional two years option period.

On behalf of the partners in Valhall, the company entered into a lease agreement for Maersk Invincible which was delivered in May 2017. The rig has mainly been used for plug and abandonment (P&A) activities and infill drilling on the Valhall area. The original contract period of five years expires in May 2022, with an additional two years option period. In addition a lease agreement for the Maersk Reacher rig was entered into in August 2018. The rig will mainly provide accommodation services on the Valhall field center for a period of two years, with an additional 12 month optional extension period.

In August 2017, the company entered into a lease agreement with Odfjell Drilling for the rig Deepsea Stavanger with an estimated lease period of 9 months in 2018. In December 2017, a new lease agreement for the same rig was entered into. This lease period is estimated to be 12 months, starting in Q2 2019.

In April 2018, the company entered into a new lease agreement with Odfjell Drilling for the rig Deepsea Nordkapp with an estimated lease period of two years, starting at the end of Q2 2019.

The company has also entered into other operating lease agreements such as rental of supply vessels and office premises. In addition the company has lease commitments pertaining to its ownership in partner operated oil and gas fields.

The operating lease expenses recognized in the Income statement were as follows:

	Group		Parent	
(USD 1 000)	2018	2017	2018	2017
Rig lease payments	206 812	113 674	206 812	113 674
Other licence related lease payments	46 394	52 347	46 394	52 347
Office premises	10 612	10 496	10 612	10 496
Payments received on subleases	-13 340	-	-13 340	-
Total	250 478	176 517	250 478	176 517

Future minimum lease payments under non-cancellable operating leases are as follows:*

	Group		Parent	
(USD 1 000)	31.12.2018	31.12.2017	31.12.2018	31.12.2017
Rigs				
Within one year	376 471	202 080	376 471	202 080
One to five years	523 575	602 029	523 575	602 029
After five years	-	-	-	-
Total rigs	900 046	804 108	900 046	804 108
Other licence related				
Within one year	36 473	62 871	36 473	62 871
One to five years	52 056	69 856	52 056	69 856
After five years	62 506	72 045	62 506	72 045
Total other licence related	151 036	204 772	151 036	204 772

Office premises				
Within one year	11 561	11 087	11 561	11 087
One to five years	32 457	36 612	32 457	36 612
After five years	5 652	14 397	5 652	14 397
Total office premises	49 671	62 096	49 671	62 096
Total future minimum lease payments	1 100 753	1 070 976	1 100 753	1 070 976
Subleases expected to be received				
Within one year	4 461	19 219	4 461	19 219
One to five years	-	4 000	-	4 000
After five years	-	-	-	-
Total subleases expected to be received	4 461	23 220	4 461	23 220
Total net future minimum lease payments	1 096 291	1 047 757	1 096 291	1 047 757

* Future minimum lease payments comprise payments over the lease term that the company is or can be required to make, excluding contingent rent, costs for services and taxes to be paid by and reimbursed to the company, in accordance with IAS 17.

Capital commitments and other contractual obligations

Nominal capital commitments and contractual obligations are as follows:

(USD 1 000)*	31.12.2018	31.12.2017
Within one year	291 693	387 754
One to five years	482 445	631 476
After five years	183 743	237 459
Total	957 881	1 256 689

* Represents Aker BP`s interest in the licences as the commitments have been fully allocated to licences for the expected periods.

Guarantees

In connection with the booking of capacity in the infrastructure on the Norwegian Continental Shelf, the operator of the infrastructure (Gassco) requires a guarantee covering the transportation cost in the coming two years. This guarantee amounts to NOK 900 million as of year end 2018 (unchanged from 2017).

The company has a bank guarantee related to withheld payroll tax of NOK 300 million.

Contingent liabilities

During the normal course of its business, the company will be involved in disputes, including tax disputes. Potential tax claims related to previous taxable income of acquired companies can to some extent be reimbursed from the sellers. The company 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.

As for other licences on the NCS, the company has unlimited liability for damage, including pollution damage. The company has insured its pro rata liability on the NCS on a par with other oil companies. Installations and liability are covered by an operational liability insurance policy.

Note 26 Transactions with related parties

Transactions with related parties

At year-end 2018, Aker (Aker Capital AS) and BP Exploration Operating Company Ltd are the two major shareholders in Aker BP, with a total ownership interest of 40.00 and 30.00 per cent. An overview of the 20 largest shareholders is provided in Note 18.

Transactions with related parties are carried out on the basis of the "arm's length" principle.

		Group		Parent	
Related party (USD 1 000)	Receivables (+) / liabilities (-)	31.12.2018	31.12.2017	31.12.2018	31.12.2017
Aker Solutions	Trade creditors	-6 759	-21	-6 759	-21
Cognite AS	Trade creditors	-1 244	-	-1 244	-
Kværner AS	Trade creditors	-1 051	-	-1 051	-
Other Aker Group Companies	Trade creditors	-706	-20	-706	-20
Other BP Group Companies	Trade creditors	-7	-	-7	-
Aker Energy Ghana	Trade debtors	564	-	564	-
BP Oil International Ltd.	Trade debtors	205 750	57 003	205 750	57 003
BP Global Investments Ltd.	Trade debtors	2 840	-	2 840	-
Other BP Group Companies	Trade debtors	349	-	349	-

		Group		Parent	
Related party (USD 1 000)	Revenues (-) / expenses (+)	2018	2017	2018	2017
Aker ASA	Board remuneration etc	258	373	258	373
First Geo AS	Exploration expenses	5 446	3 234	5 446	3 234
Kværner AS	Other operating expenses	68 616	829	68 616	829
Aker Solutions	Development costs	206 081	30 658	206 081	30 658
Aker Energy Ghana	Recharge of consultants and shared services	-12 149	-	-12 149	-
Akastor Real Estate AS	Office rental	1 289	-	1 289	-
Cognite AS	Operating expenses	11 425	2 488	11 425	2 488
OCY Alexandra	Platform supply vessel leases	10 689	3 315	10 689	3 315
Other Aker companies	Operating expenses	2 839	1 141	2 787	1 141
BP Exploration Operating Company Ltd	Other operating expenses	1 870	-62	1 870	-62
BP International Ltd	Other operating expenses	1 182	-	1 182	-
Other BP Group Companies	Other operating expenses	-1 532	-	-1 532	-
BP Oil International	Sales of Oil and NGL	-3 297 563	-468 566	-3 297 563	-468 566
BP Gas Marketing	Sales of Gas	-380 389	-32 724	-380 389	-32 724

Note 27 Financial instruments

Capital structure and equity

The main objective of the company's management of the capital structure is to maximize return to the owners by ensuring competitive conditions for both the company's own capital and borrowed capital.

The size of the company's resource and reserve base is very important in relation to access to capital and borrowing terms. The increase in resources, reported reserves and equity ratio as a result of large acquisitions in the recent years has significantly strengthened the company's ability to obtain attractive terms and conditions for its debt portfolio. The company seeks to optimize its capital structure by balancing return on equity against liquidity requirements.

The company monitors changes in financing needs, risk, assets and cash flows, and evaluates the capital structure continuously. To maintain the desired capital structure, the company considers various types of capital transactions, including refinancing of its debt, purchase or issue new shares or debt instruments, sell assets or pay back capital to the owners.

Unless specified otherwise, the numbers below apply both to the group and the parent.

Categories of financial assets and liabilities

The company has the following financial assets and liabilities: financial assets and liabilities recognized at fair value through profit or loss, cash and receivables, and other liabilities. The latter two are recognized in the accounts at amortized cost, while the first item is recognized at fair value.

Categories of financial assets and financial liabilities - Group and parent

31.12.2018	Financial assets at fair value designated as such upon initial recognition	Cash and receivables	Financial liabilities at fair value designated as such upon initial recognition	Financial liabilities measured at amortized costs	Total
Assets					
Accounts receivable	-	162 798	-	-	162 798
Tax receivable	-	11 082	-	-	11 082
Other short-term receivables*	-	296 188	-	-	296 188
Cash and cash equivalents	-	44 944	-	-	44 944
Derivatives	17 253	-	-	-	17 253
Total financial assets	17 253	515 012	-	-	532 265
Liabilities					
Derivatives	-	-	35 058	-	35 058
Trade creditors	-	-	-	105 567	105 567
Bonds	-	-	-	1 110 488	1 110 488
Other interest bearing debt	-	-	-	907 954	907 954
Other short-term liabilities	-	-	-	590 860	590 860
Total financial liabilities	-	-	35 058	2 714 870	2 749 928

* Prepayments are not included in other short-term receivables, as they do not meet the definition of financial instruments.

31.12.2017	Financial assets at fair value designated as such upon initial recognition	Cash and receivables	Financial liabilities at fair value designated as such upon initial recognition	Financial liabilities measured at amortized costs	Total
Assets					
Accounts receivable	-	99 752	-	-	99 752
Tax receivable	-	1 586 006	-	-	1 586 006
Other short-term receivables*	-	442 600	-	-	442 600
Cash and cash equivalents	-	232 504	-	-	232 504
Derivatives	15 149	-	-	-	15 149
Total financial assets	15 149	2 360 862	-	-	2 376 012
Liabilities					
Derivatives	-	-	21 396	-	21 396
Trade creditors	-	-	-	32 847	32 847
Bonds	-	-	-	622 039	622 039
Other interest bearing debt	-	-	-	2 766 930	2 766 930
Other short-term liabilities	-	-	-	704 197	704 197
Total financial liabilities	-	-	21 396	4 126 012	4 147 408

* Prepayments are not included in other short-term receivables, as they do not meet the definition of financial instruments.

Financial risk

The company has financed its activities with reserve-based lending, a bridge facility (see Note 23) and three bonds (see Note 19). In addition, the company has financial instruments such as accounts receivable, trade creditors etc., directly related to its day-to-day operations. For hedging purposes, the company has different types of economic hedging instruments, but no hedge accounting is applied. Commodity derivatives are used to hedge the risk of oil price reduction. Foreign currency exchange contracts and options are used in order to reduce currency risk related to cash flows. The company manages a portion of its interest rate exposure with a cross currency interest rate swap and interest rate derivatives.

The most important financial risks which the company is exposed to relate to oil and gas prices, foreign exchange rates, interest rates and access to competitively priced funding.

The company's risk management, including financial risk management, is designed to ensure identification, analysis and systematic and cost-efficient handling of risk. Established management procedures provide a good basis for reporting and monitoring of the company's financial risk exposure.

(i) Commodity price risk

Aker BP's revenues are derived from the sale of petroleum products, and the revenue flow is therefore exposed to oil and gas price fluctuations. The company is continuously evaluating and assessing opportunities for hedging as part of a prudent financial risk management process. In 2018 the company entered into new commodity hedges for 2019. These are put options with an average strike price 55 USD/bbl, for approximately 12 per cent of estimated 2019 oil production, corresponding to approximately 40 per cent of the after tax value.

In 2018 the company had put options in place with a strike of 50, 55 and 60 USD/bbl. for approximately 22 per cent of the 2018 oil production, corresponding to approximately 75 per cent of the after-tax value.

The following table summarizes the sensitivity of the commodity derivatives to a reasonably possible change in the forward oil price as of 31 December 2018, with all other variables held constant. As the company has not hedged production after 2019, the calculation is based on 2019 forward curve only. The impact presented below is on the fair value of the commodity derivatives only, and does not include other Income statement effects from changes in oil prices.

(USD 1 000)	Increase/decrease in oil price	31.12.2018	31.12.2017
Effect on pre-tax profit/loss:	+ 30%	-27 141	-2 676
	- 30%	72 889	29 204

(ii) Currency risk

Revenues from sale of petroleum and gas are mainly in USD, EUR and GBP, while expenditures are mainly in NOK, USD, EUR and GBP. Sales and expenses in the same currency contribute to mitigating some of the currency risk. Currency derivatives may be used to further reduce this risk.

The table below shows the company's exposure in NOK as of 31 December:

Exposure relating to (USD 1 000)	31.12.2018	31.12.2017
Tax receivables, cash and cash equivalents, other short-term receivables and deposits	191 599	2 122 165
Trade creditors, tax payable and other short-term liabilities	-1 050 045	-1 058 283
Bonds	-218 878	-230 375
Net exposure to NOK	-1 077 324	833 507

The amounts above do not include tax balances in NOK, as they are not deemed to be financial instruments.The company's management of currency risk takes into account the USD values of non-USD assets, liabilities, opex and investments over time, including those exposures arising from the requirement to perform the tax calculation in NOK while the company's functional currency is USD.

The company is also exposed to change in other exchange rates such as GBP/USD and EUR/USD, but the amounts are deemed immaterial.

The table below shows the impact on profit/loss from changes in USD/NOK exchange rate. Other currencies are not included as the exposure is deemed immaterial.

(USD 1 000)	Change in exchange rate	31.12.2018	31.12.2017
Effect on pre-tax profit/loss:	+ 10%	16 040	-85 631
	- 10%	-12 779	153 499

The sensitivity above includes the impact from currency derivatives.

(iii) Interest-rate risk

The company is exposed to interest-rate risk to borrowings and cash deposits. Floating-interest loans involve risk exposure for the company's future cash flows. As of 31 December 2018, the company's total loan liabilities exposed to interest risk amounted to approximately USD 2.1 billion, distributed between long-term bonds and the reserve-based lending facility. The corresponding loan liabilities as of 31 December 2017 amounted to approximately USD 3.1 billion.

The terms of the company's loans are described in Notes 19 and 23. The interest-rate risk relating to cash and cash equivalents is relatively limited. The following table shows the company's sensitivity to potential changes in interest rates which is reasonably possible:

Change in interest rate level in basis points (USD 1 000)		31.12.2018	31.12.2017
Effect on pre-tax profit/loss:	+ 100 points	-112	-18 213
	- 100 points	1 276	15 462

In order to calculate sensitivity of interest rate changes, floating interest rates have been changed by + / - 100 basis points.

The table presents the annual effect on profit and loss for the financial instruments exposed to interest risk at the balance sheet date. Any changes in interest rates will impact the fair value of interest-rate swaps, as the floating rate interest received on the interest rate swaps is associated with a corresponding floating rate interest payment on a bond or a loan. A change in fair value on the interest rate swaps has reduced the exposure to interest-rate risk by USD 11.6 million in the sensitivity presented.

(iv) Liquidity risk/liquidity management

The company's liquidity risk is the risk that it will not be able to meet its financial obligations as they fall due.

Short-term (12 months) and long-term (five years) forecasts are prepared on a regular basis to plan the company's liquidity requirements. These plans are updated regularly for various scenarios and form part of the decision basis for the company's management and Board of Directors.

Excess liquidity is defined as a portfolio consisting of liquid assets other than the funds deposited in regular operational bank accounts and unused credit facilities. For excess liquidity, the requirement for low liquidity risk (i.e. the risk of realization on short notice) is generally more important than maximizing the return.

The company's objective for the placement and management of excess capital is to maintain a low risk profile and good liquidity.

The company's liquid assets as of 31 December 2018 are mainly deposited in bank accounts. As of 31 December 2018, the company had cash reserves of USD 45 million (2017: USD 233 million). Revenues and expenses are carefully managed on a day-to-day basis for liquidity risk management purposes.

The table below shows the payment structure for the company's financial commitments, based on undiscounted contractual payments:

		Contract related cash flow				
31.12.2018	Book value	Less than 1 year	1-2 years	2-5 years	over 5 years	SUM
Non-derivative financial liabilities:						
Bonds	1 110 488	70 333	287 106	517 474	539 811	1 414 723
Other interest bearing debt	907 954	34 108	927 851	-	-	961 959
Trade creditors and other liabilities	696 427	696 427	-	-	-	696 427
Derivative financial liabilities						
Derivatives	35 058	8 783	26 275	-	-	35 058
Total as of 31.12.2018	2 749 928	809 651	1 241 231	517 474	539 811	3 108 167

		Contract related cash flow				
31.12.2017	Book value	Less than 1 year	1-2 years	2-5 years	over 5 years	SUM
Non-derivative financial liabilities:						
Bonds	622 039	41 367	41 367	717 907	-	800 642
Other interest bearing debt	2 766 930	1 574 001	47 751	1 357 855	-	2 979 608
Trade creditors and other liabilities	711 049	711 049	-	-	-	711 049
Derivative financial liabilities						
Derivatives	21 396	7 691	-	13 705	-	21 396
Total as of 31.12.2017	4 121 414	2 334 109	89 119	2 089 467	-	4 512 694

(v) Credit risk

The risk of counterparties being financially incapable of fulfilling their obligations is regarded as minor as there have not historically been any losses on accounts receivable. The company's customers and licence partners are mainly large and credit worthy oil companies, and it has thus not been necessary to make any provision for credit losses.

In the management of the company's liquid assets, low credit risk is prioritized. Liquid assets are generally placed in bank deposits that represent a low credit risk.

The maximum credit risk exposure corresponds to the book value of financial assets. The company deems its maximum risk exposure to correspond with the book value of accounts receivable and other short-term receivables, see notes 14 and 15.

Determination of fair value

The fair value of forward exchange contracts is determined using the forward exchange rate at the end of the reporting period. The fair value of commodity derivatives is determined using the forward Brent blend curve at the end of the reporting period. The fair value of interest rate swaps and cross currency interest rate swaps is determined by using the expected floating interest rates at the end of the period and is confirmed by external market sources. See Note 21 for detailed information about the derivatives.

The following of the company's financial instruments have not been valued at fair value: trade debtors, other short-term receivables, other long-term receivables, short-term loans and other short-term liabilities, bonds and other interest bearing liabilities.

The carrying amount of cash and cash equivalents is approximately equal to fair value, since these instruments have a short term to maturity. Similarly, the carrying amount of accounts receivable, other receivables, trade creditors and other short-term liabilities is virtually the same as their fair value as they are entered into on ordinary terms and conditions.

The bond issued September 2013 is listed on Oslo Børs, and the fair value for disclosure purposes is determined using the quoted value as of 31 December 2018.
Both the USD 6% and 5,875% Senior Notes are listed on The International Stock Exchange, and the fair values for disclosure purposes are determined using the quoted value as of 31 December 2018. For the RBL facility, the fair value is assessed to equal the book value.

The following is a comparison between the book value and fair value of the company's financial instruments, except those where the carrying amount is a reasonable approximation of fair value (such as short-term trade receivables and payables in addition to instruments measured to fair value).

	31.12.2018		31.12.2017	
Fair value of financial instruments (USD 1 000)	Book value	Fair value	Book value	Fair value
Financial liabilities measured at amortized cost:				
Bonds	1 110 488	1 148 533	622 039	691 189
Other interest-bearing debt	907 954	907 954	2 766 930	2 766 930
Total financial liabilities	2 018 443	2 056 488	3 388 969	3 458 119

Fair value hierarchy

The company classifies fair value measurements by employing a value hierarchy that reflects the significance of the input used in preparing the measurements. The fair value hierarchy consists of the following levels:

Level 1 - input in the form of listed (unadjusted) prices in active markets for identical assets or liabilities.

Level 2 - input other than listed prices of assets and liabilities included in Level 1 that is observable for assets or liabilities, either directly (i.e. as prices) or indirectly (i.e. derived from prices).

Level 3 - input for assets or liabilities for which there is no observable market data (non-observable input).

The company has no assets or liabilities in Level 3.

31.12.2018 Financial instruments recognized at fair value (USD 1 000)	Level 1	Level 2	Level 3
Financial assets or liabilities measured at fair value with changes in value recognized through profit or loss			
Derivatives	-	-17 805	-

31.12.2017 Financial instruments recognized at fair value (USD 1 000)	Level 1	Level 2	Level 3
Financial assets or liabilities measured at fair value with changes in value recognized through profit or loss			
Derivatives	-	6 247	-

In the course of the reporting period, there were no changes in the fair value measurements that involved any transfers between levels.

Reconciliation of liabilities arising from financing activities

The table below shows a reconciliation between the opening and the closing balances in the statement of financial position for liabilities arising from financing activities.

			Non-cash changes			
	31.12.2017	Cash flows	Amortization	Currency	Other fin exp	31.12.2018
Long-term interest-bearing debt	1 270 556	-380 000	17 398	-	-	907 954
Short-term interest-bearing debt	1 496 374	-1 500 000	3 626	-	-	-
Bonds	622 039	492 266	8 694	-12 511	-	1 110 488
Net cash received from issuanse of new shares	-	-	-	-	-	-
Paid dividend	-	-450 000	-	-	-	-
Totals	3 388 969	-1 837 734	29 718	-12 511	-	1 568 443

			Non-cash changes			
	31.12.2016	Cash flows	Amortization	Currency	Other fin exp*	31.12.2017
Long-term interest-bearing debt	2 030 209	-777 168	17 516	-	-	1 270 556
Short-term interest-bearing debt	-	1 496 193	180	-	-	1 496 374
Bonds	510 337	59 949	10 551	10 982	30 220	622 039
Net cash received from issuanse of new shares	-	489 436	-	-	-	-
Paid dividend	-	-250 000	-	-	-	-
Totals	2 540 546	1 018 410	28 247	10 982	30 220	3 388 969

* Other financial expenses represents the early redemption fee related to the repayment of DETNOR03.

Note 28 Investments in joint operations

Fields operated:	31.12.2018	31.12.2017
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:	31.12.2018	31.12.2017	Licence:	31.12.2018	31.12.2017
PL 001B	35.000 %	35.000 %	PL 659	50.000 %	50.000 %
PL 006B	90.000 %	90.000 %	PL 677***	0.000 %	60.000 %
PL 019	80.000 %	80.000 %	PL 685**	40.000 %	0.000 %
PL 019C	80.000 %	80.000 %	PL 724***	0.000 %	40.000 %
PL 019E****	80.000 %	0.000 %	PL 724B***	0.000 %	40.000 %
PL 026*	92.130 %	0.000 %	PL 748	50.000 %	50.000 %
PL 026B	90.260 %	90.260 %	PL 748B	50.000 %	50.000 %
PL 027D	100.000 %	100.000 %	PL 762	20.000 %	20.000 %
PL 028B	35.000 %	35.000 %	PL 777	40.000 %	40.000 %
PL 033	90.000 %	90.000 %	PL 777B	40.000 %	40.000 %
PL 033B	90.000 %	90.000 %	PL 777C	40.000 %	40.000 %
PL 036C	65.000 %	65.000 %	PL 777D****	40.000 %	0.000 %
PL 036D	46.904 %	46.904 %	PL 784	40.000 %	40.000 %
PL 036E**	64.000 %	0.000 %	PL 790	30.000 %	30.000 %
PL 065	55.000 %	55.000 %	PL 814	40.000 %	40.000 %
PL 065B****	55.000 %	0.000 %	PL 818	40.000 %	40.000 %
PL 088BS	65.000 %	65.000 %	PL 818B****	40.000 %	0.000 %
PL 102D*	50.000 %	0.000 %	PL 821***	0.000 %	60.000 %
PL 102F*	50.000 %	0.000 %	PL 821B***	0.000 %	60.000 %
PL 102G*	50.000 %	0.000 %	PL 822S	60.000 %	60.000 %
PL 102H**	50.000 %	0.000 %	PL 839	23.835 %	23.835 %
PL 127C**	100.000 %	0.000 %	PL 843	40.000 %	40.000 %
PL 146**	77.800 %	0.000 %	PL 858	40.000 %	40.000 %
PL 150	65.000 %	65.000 %	PL 861	50.000 %	50.000 %
PL 150B***	0.000 %	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 %	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****	60.000 %	0.000 %
PL 261	50.000 %	50.000 %	PL 907****	60.000 %	0.000 %
PL 262	30.000 %	30.000 %	PL 914S****	34.786 %	0.000 %
PL 300	55.000 %	55.000 %	PL 915****	35.000 %	0.000 %
PL 333**	77.800 %	0.000 %	PL 916****	40.000 %	0.000 %
PL 340	65.000 %	65.000 %	PL 919****	65.000 %	0.000 %
PL 340BS	65.000 %	65.000 %	PL 932****	60.000 %	0.000 %
PL 364	90.260 %	90.260 %	PL 941****	50.000 %	0.000 %
PL 442	90.260 %	90.260 %	PL 948****	40.000 %	0.000 %
PL 442B	90.260 %	90.260 %	PL 951****	40.000 %	0.000 %
PL 460	65.000 %	65.000 %	PL 963****	70.000 %	0.000 %
PL 504	47.593 %	47.593 %	PL 964****	40.000 %	0.000 %
PL 626**	60.000 %	50.000 %			
Number of licenses in which Aker BP is the operator				83	62

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

** Acquired/changed through licence transactions or licence splits.

*** Relinquished license or Aker BP has withdrawn from the license.

**** Interest awarded in the APA Licensing round (Application in predefined Areas) in 2017 and 2018. The awards were announced in 2018.

Fields non-operated:	31.12.2018	31.12.2017
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***	0.000 %	5.000 %

Production licences in which Aker BP is a partner:

Licence:	31.12.2018	31.12.2017	Licence:	31.12.2018	31.12.2017
PL 006C	15.000 %	15.000 %	PL 719	20.000 %	20.000 %
PL 006E****	15.000 %	0.000 %	PL 721	40.000 %	40.000 %
PL 018DS	13.338 %	13.338 %	PL 722	20.000 %	20.000 %
PL 026*	0.000 %	30.000 %	PL 782S	20.000 %	20.000 %
PL 029B	20.000 %	20.000 %	PL 782SB	20.000 %	20.000 %
PL 035	50.000 %	50.000 %	PL 782SC	20.000 %	20.000 %
PL 035C	50.000 %	50.000 %	PL 810	30.000 %	30.000 %
PL 038***	0.000 %	5.000 %	PL 810B****	30.000 %	0.000 %
PL 048D	10.000 %	10.000 %	PL 811	20.000 %	20.000 %
PL 102C	10.000 %	10.000 %	PL 813	3.300 %	3.300 %
PL 102D*	0.000 %	10.000 %	PL 838	30.000 %	30.000 %
PL 102F*	0.000 %	10.000 %	PL 842	30.000 %	30.000 %
PL 102G*	0.000 %	10.000 %	PL 844	20.000 %	20.000 %
PL 127**	50.000 %	0.000 %	PL 852	40.000 %	40.000 %
PL 127B**	50.000 %	0.000 %	PL 852B****	40.000 %	0.000 %
PL 220	15.000 %	15.000 %	PL 852C****	40.000 %	0.000 %
PL 265	20.000 %	20.000 %	PL 857	20.000 %	20.000 %
PL 272	50.000 %	50.000 %	PL 862	50.000 %	50.000 %
PL 405	15.000 %	15.000 %	PL 863	40.000 %	40.000 %
PL 457BS	40.000 %	40.000 %	PL 863B****	40.000 %	0.000 %
PL 492	60.000 %	60.000 %	PL 864	20.000 %	20.000 %
PL 502	22.222 %	22.222 %	PL 871**	0.000 %	20.000 %
PL 533	35.000 %	35.000 %	PL 891	30.000 %	30.000 %
PL 533B****	35.000 %	0.000 %	PL 892	30.000 %	30.000 %
PL 554	30.000 %	30.000 %	PL 902	30.000 %	30.000 %
PL 554B	30.000 %	30.000 %	PL 942****	30.000 %	0.000 %
PL 554C	30.000 %	30.000 %	PL 954****	20.000 %	0.000 %
PL 554D****	30.000 %	0.000 %	PL 955****	30.000 %	0.000 %
PL 615**	4.000 %	0.000 %	PL 961****	30.000 %	0.000 %
PL 615B**	4.000 %	0.000 %	PL 962****	20.000 %	0.000 %
PL 627***	0.000 %	20.000 %	PL 966****	30.000 %	0.000 %
PL 627B***	0.000 %	20.000 %			
Number of licenses in which Aker BP is the parnter				49	46

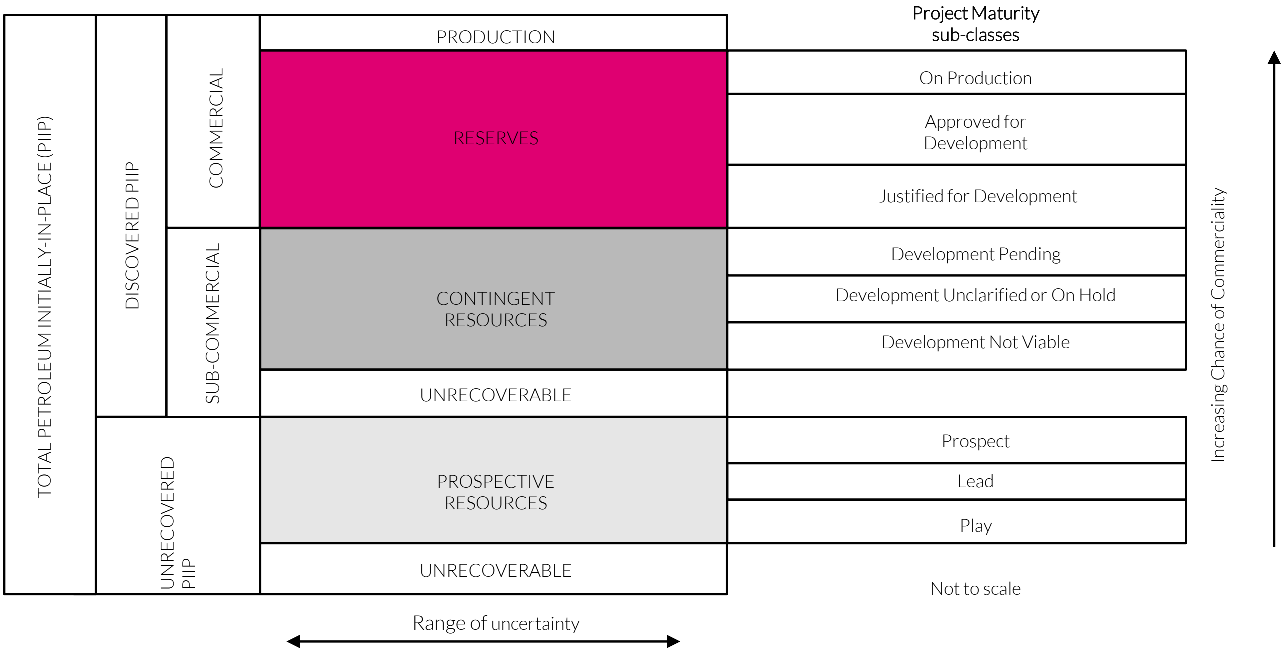
* Aker BP became the operator of the license during 2018.
** Acquired/changed through licence transactions or licence splits.
*** Relinquished license or Aker BP has withdrawn from the license.
**** Interest awarded in the APA Licensing round (Application in predefined Areas) in 2017 and 2018. The awards were announced in 2018.

Note 29 Classification of reserves and contingent resources (unaudited)

Classification of reserves and contingent resources

Aker BP ASA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE's) "Petroleum Resources Management System". This classification system is consistent with Oslo Børs requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification systme is illustrated in Figure 1.

Figure 1 - SPE's classification system used by Aker BP ASA



Reserves, developed and non-developed

All reserve estimates are based on all available data including seismic, well logs, core data, drill stem tests and production history. Industry standards are used to establish 1P and 2P. This includes decline analysis for mature fields in which reliable trends are established. For undeveloped fields and less mature producing fields reservoir simulation models or simulations models in combination with decline analysis has been used for profile generation.

Note that an independent third party, AGR Petroleum Services AS, has certified 1P and 2P reserves for all Aker BP assets except for the minor assets Atla and Enoch, representing approximately 0.002 per cent of total 2P reserves. Note also that production numbers are preliminary pr November 2018, leaving numbers for the last two months of 2018 as estimates. These final numbers may be slightly different.

Aker BP ASA has a working interest in 40 fields/projects containing reserves, see Table 1 and 2. Out of these fields/projects, 16 are in the sub-class "On Production"/Developed, 19 are in the sub-class "Approved for Development"/Undeveloped and four are in the sub-class "Justified for Development"/Undeveloped. Note that several fields have reserves in more than one reserve sub-class.

Table 1 - Aker BP fields - Developed reserves

Field/project	Investment share	Operator	Resource class
Alvheim (Norwegian part, including Kameleon, Kneler, Boa and Viper/Kobra)	65.00 %	Aker BP	On production
Boa (Previousley included in Alvheim)	57.62 %	Aker BP	On production
Vilje	46.90 %	Aker BP	On production
Volund	65.00 %	Aker BP	On production
Bøyla	65.00 %	Aker BP	On production
Atla	10.00 %	Total	On production
Ula	80.00 %	Aker BP	On production
Tambar	55.00 %	Aker BP	On production
Tambar Øst	46.20 %	Aker BP	On production
Valhall	90.00 %	Aker BP	On production
Hod	90.00 %	Aker BP	On production
Skarv	23.84 %	Aker BP	On production
Ærfugl (A-1H)	23.84 %	Aker BP	On production
Ivar Aasen	34.79 %	Aker BP	On production
Gina Krog	3.30 %	Equinor	On production
Enoch	2.00 %	Repsol Sinopec	On production

Table 2 - Aker BP fields - Undeveloped reserves

Field/project	Investment share	Operator	Resource class
Johan Sverdrup	11.57 %	Statoil	Approved for development
Hanz	34.79 %	Aker BP	Approved for development
Alvheim Kameleon Gas Cap Blow Down	65.00 %	Aker BP	Approved for development
Alvheim Kameleon Infill South	65.00 %	Aker BP	Approved for development
Frosk Test Production	65.00 %	Aker BP	Approved for development
Skogul	65.00 %	Aker BP	Approved for development
Volund Sidetrack North	65.00 %	Aker BP	Approved for development
Valhall Flank North Infill drilling	90.00 %	Aker BP	Approved for development
Valhall Flank North Water Injection	90.00 %	Aker BP	Approved for development
Valhall Flank South Infill drilling	90.00 %	Aker BP	Approved for development
Valhall Flank West Project	90.00 %	Aker BP	Approved for development
Valhall IP Drilling Program	90.00 %	Aker BP	Approved for development
Ula drilling phase 1	80.00 %	Aker BP	Approved for Development
Tambar K2 Workover	55.00 %	Aker BP	Approved for Development
Tambar Artificial Lift	55.00 %	Aker BP	Approved for Development
Ærfugl Phase 1	23.80 %	Aker BP	Approved for Development
Ærfugl Phase 2	23.80 %	Aker BP	Approved for Development
Snadd Outer	30.00 %	Aker BP	Approved for Development
Oda	15.00 %	Spirit Energy	Approved for Development
Ivar Aasen Skagerak Infill	34.79 %	Aker BP	Justified for Development
Ivar Aasen Alluvial Fan Infill	34.79 %	Aker BP	Justified for Development
Frosk test production Part 2	65.00 %	Aker BP	Justified for Development
Valhall WP Production recovery	90.00 %	Aker BP	Justified for Development

Total net proven reserves (1P/P90) as of 31 December 2018 to Aker BP ASA are estimated at 683 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 917 million barrels of oil equivalents. The split between liquid and gas and between the different subcategories are given in tables 3 and 4.

Table 3 - Reserves by field and area

31.12.2018	1P / P90 (low estimate) Gross oil (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	2P / P50 (best estimate) Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Alvheim (incl. Boa)	47	-	18	65	41	70	-	33	102	65
Volund	11	-	2	13	8	16	-	3	20	13
Vilje	10	-	-	10	5	15	-	-	15	7
Bøyla	3	-	0	3	2	5	-	0	5	3
Skogul	5	-	1	6	4	9	-	1	10	6
Frosk	3	-	0	3	2	5	-	0	5	4
Alvheim Area	**79**	**-**	**21**	**100**	**62**	**120**	**-**	**37**	**157**	**98**
Ula	30	1	-	31	25	47	2	-	49	39
Tambar	5	0	1	6	4	10	0	3	14	7
Tambar East	-	-	-	-	-	0	0	0	0	0
Ula Area	**35**	**1**	**1**	**38**	**28**	**58**	**2**	**3**	**63**	**47**
Valhall	197	9	33	239	215	261	12	44	316	285
Hod	3	0	0	3	3	3	0	0	4	4
Valhall Area	**200**	**9**	**34**	**242**	**218**	**264**	**12**	**45**	**320**	**288**
Ivar Aasen	73	4	13	89	31	116	6	18	140	49
Hanz	11	0	2	13	4	14	1	2	17	6
Ivar Aasen Area	**83**	**4**	**14**	**101**	**35**	**130**	**6**	**21**	**157**	**55**
Ærfugl	24	27	128	180	45	37	41	191	268	67
Skarv	25	22	101	148	35	37	22	104	163	39
Skarv Area	**49**	**49**	**229**	**328**	**80**	**74**	**63**	**294**	**431**	**106**
Johan Sverdrup	**2 063**	**43**	**55**	**2 160**	**250**	**2 559**	**54**	**68**	**2 681**	**310**
Atla	-	-	-	-	-	-	-	-	-	-
Enoch	-	-	-	-	-	1	-	-	1	0
Gina Krog	49	23	52	124	4	67	25	79	171	6
Oda	28	-	1	30	4	45	-	2	47	7
Other	**77**	**23**	**53**	**154**	**9**	**114**	**25**	**81**	**219**	**13**
Total					**683**					**917**

Table 4 - Reserves by project and reserve class

On production 31.12.2018	Interest %	1P / P90 (low estimate) Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	2P / P50 (best estimate) Gross oil (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Alvheim	65.0 %	37	-	4	40	26	50	-	7	57	37
Boa	57.6 %	7	-	2	9	5	16	-	4	20	12
Vilje	46.9 %	10	-	-	10	5	15	-	-	15	7
Volund	65.0 %	10	-	2	12	8	15	-	3	18	12
Bøyla	65.0 %	3	-	0	3	2	5	-	0	5	3
Atla	10.0 %	-	-	-	-	-	-	-	-	-	-
Enoch	2.0 %	-	-	-	-	-	1	-	-	1	0
Ula	80.0 %	12	0	-	13	10	18	1	-	19	15
Tambar	55.0 %	2	0	0	2	1	4	0	1	5	3
Tambar East	46.2 %	-	-	-	-	-	0	0	0	0	0
Valhall	90.0 %	113	5	17	135	121	145	6	22	174	156
Hod	90.0 %	3	0	0	3	3	3	0	0	4	4
Skarv	23.8 %	25	22	101	148	35	37	22	104	163	39
Ærfugl A-1H	23.8 %	3	3	15	21	5	4	4	21	29	7
Ivar Aasen	34.8 %	67	3	12	82	28	104	5	16	125	44
Gina Krog	3.3 %	49	23	52	124	4	67	25	79	171	6
Total						255					344

Approved for development 31.12.2018	Interest %	1P / P90 (low estimate) Gross oil (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	2P / P50 (best estimate) Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Johan Sverdrup	11.6 %	2 063	43	55	2 160	250	2 559	54	68	2 681	310
Hanz	34.8 %	11	0	2	13	4	14	1	2	17	6
Alvheim Kam. Gas Cap Blow Down	65.0 %	-	-	12	12	8	-	-	21	21	14
Alvheim Kameleon Infill South	65.0 %	3	-	0	3	2	4	-	0	4	3
Frosk Test Production	65.0 %	1	-	0	1	1	2	-	0	2	1
Skogul	65.0 %	5	-	1	6	4	9	-	1	10	6
Volund Sidetrack North	65.0 %	1	-	0	1	1	1	-	0	1	1
Valhall Flank North Infill drilling	90.0 %	1	0	0	2	2	3	0	0	3	3
Valhall Flank North Water Injection	90.0 %	6	0	0	6	5	7	0	0	7	7
Valhall Flank South Infill drilling	90.0 %	5	0	1	6	6	8	0	1	10	9
Valhall Flank West Project	90.0 %	39	2	8	49	44	52	3	11	66	59
Valhall IP drilling programme	90.0 %	20	1	3	25	22	26	1	4	31	28
Ula drilling phase 1	80.0 %	18	1	-	18	15	29	1	-	30	24
Tambar K2 Workover	55.0 %	2	0	0	2	1	3	0	1	4	2
Tambar Artificial Lift	55.0 %	2	0	0	2	1	3	0	1	4	2
Ærfugl Phase 1	23.8 %	12	12	55	79	19	18	18	82	118	28
Ærfugl Phase 2	23.8 %	5	6	30	42	10	8	11	50	69	17
Snadd Outer	30.0 %	4	6	28	38	11	6	8	38	52	15
Oda	15.0 %	28	-	1	30	4	45	-	2	47	7
Total						410					543

Justified for development 31.12.2018	Interest %	1P / P90 (low estimate) Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	2P / P50 (best estimate) Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Frosk test production Part 2	65.0 %	1	-	0	1	1	3	-	0	3	2
Ivar Aasen Skagerak Infill	34.8 %	4	0	1	5	2	8	0	1	10	3
Ivar Aasen Alluvial Fan Infill	34.8 %	2	0	0	2	1	4	0	1	5	2
Valhall WP Production recovery	90.0 %	12	1	3	16	14	19	1	5	26	23
Total						18					30
Total reserves 31.12.2018						683					917
Total reserves 31.12.2017						692					914

Changes from the 2017 reserve report are summarized in Table 5. The main reasons for increased net reserve estimate are the continued optimization of the Valhall field (34.5 mmboe) and Phase 2 PDO decision on Johan Sverdrup (10 mmboe).

An oil price of 70 USD/bbl (2019) and 65 USD/bbl (following years) has been used for reserve estimation. Low- and high case sensitivities with oil prices of 45 and 81.3 USD/bbl, respectively, have been performed by AGR. This had only minor effect on the reserve estimates. The low price resulted in a reduction in total net proven (1P/P90) reserves of 4% and net proven plus probable (2P/P50) reserves of 2.5%. The high oil price resulted in an increase of 0.9% and 0.1% for proven (1P/P90) and proven plus probable (2P/P50), respectively.

Table 5 - Aggregated reserves, production, developments, and adjustments

Net attributed million barrels of oil equivalent	On production		Approved for devlop.		Justified for devlop.		Total	
(mmboe)	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31.12.2017	270	363	324	415	97	136	692	914
Production	-56	-56	-	-	-	-	-56	-56
Transfer	5	9	91	126	-97	-136	-	-
Revisions	34	27	-30	-39	-	-	4	-12
IOR	-	-	-	-	-	-	-	-
Discovery and extensions	-	-	25	40	18	30	43	71
Acquisition and sale	-	-	-	-	-	-	-	-
Balance as of 31.12.2018	254	343	410	543	18	31	683	917
Delta	-16	-20	86	128	-79	-105	-9	3

Note 30 Events after the balance sheet date

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

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 and the group's financial statements for 2018 have been prepared in accordance with IFRS, as adopted by the EU, and requirements in accordance with the Norwegian Accounting Act. The information presented in the financial statements gives a true and fair view of the company's liabilities, financial position and results overall.

To the best of our knowledge, the Board of Directors' Report gives a true and fair view of the development, performance and financial position of the company, and includes a description of the principal risk and uncertainty factors facing the company and the group. Additionally, we confirm to the best of our knowledge that the report 'Payment to governments' as provided in a separate section in this annual report has been prepared in accordance with the requirements in the Norwegian Securities Trading Act Section 5-5a with pertaining regulations.

The Board of Directors of Aker BP ASA

Akerkvartalet, 13 March 2019

ØYVIND ERIKSEN **Chairman**	ANNE MARIE CANNON **Deputy chair**	KJELL INGE RØKKE **Board member**
TROND BRANDSRUD **Board member**	GRO KIELLAND **Board member**	BERNARD LOONEY **Board member**
KATE THOMSON **Board member**	INGARD HAUGEBERG **Board member**	ANETTE HOEL HELGESEN **Board member**
ØRJAN HOLSTAD **Board member**	TERJE SOLHEIM **Board member**	KARL JOHNNY HERSVIK **Chief Executive Officer**

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.

<u>Abandonment spend (abex)</u> is payment for removal and decommissioning of oil fields

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

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

<u>Capex</u> is disbursements on investments in fixed assets deducted by capitalized interest cost

<u>EBIT</u> is short for earnings before interest and other financial items and taxes

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

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

<u>Equity ratio</u> is total equity divided by total assets

<u>Exploration spend (expex)</u> is exploration expenses plus additions to capitalized exploration wells less dry well expenses

<u>Leverage ratio</u> is calculated as Net interest-bearing debt divided by twelve months rolling EBITDAX

<u>Net interest-bearing debt</u> is book value of current and non-current interest-bearing debt less cash and cash equivalents

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

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To the General Meeting of Aker BP ASA

Independent Auditor's Report

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of Aker BP ASA. The financial statements comprise:

- The financial statements of the parent company Aker BP ASA (the Company), which comprise the statement of financial position as at 31 December 2018, and income statement, statement of comprehensive income, statement of changes in equity, statement of cash flow for the year then ended, and notes to the financial statements, including a summary of significant accounting policies, and

- The consolidated financial statements of Aker BP ASA and its subsidiaries (the Group), which comprise the statement of financial position as at 31 December 2018, and income statement, statement of comprehensive income, statement of changes in equity, statement of cash flow for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion:

- The financial statements are prepared in accordance with the law and regulations.

- The accompanying financial statements give a true and fair view of the financial position of the Company as at 31 December 2018, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU.

- The accompanying consolidated financial statements give a true and fair view of the financial position of the Group as at 31 December 2018, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU.

Basis for Opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company and the Group as required by laws and regulations, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the current period. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

KPMG AS, a Norwegian limited liability company and member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.

Statsautoriserte revisorer - medlemmer av Den norske Revisorforening

Offices in:

Oslo	Elverum	Mo i Rana	Stord
Alta	Finnsnes	Molde	Straume
Arendal	Hamar	Skien	Tromsø
Bergen	Haugesund	Sandefjord	Trondheim
Bodø	Knarvik	Sandnessjøen	Tynset
Drammen	Kristiansand	Stavanger	Ålesund

Impairment of licence assets and associated goodwill

Refer to Board of Directors' report and financial statement Note 1.3 (Important accounting judgments, estimates and assumptions), Note 1.12 (Impairment accounting policy) and Note 13 (Impairments).

The key audit matter	_How the matter was addressed in our audit_
The recoverable amounts of licence assets and the associated goodwill are sensitive to changes in market assumptions, in particular oil and gas prices, discount rate and forecast operational performance including the volumes of oil and gas to be produced and licence related expenditures. Any negative developments in these assumptions and forecasts, may be an impairment trigger, even if other factors have moved favourably. In addition, the goodwill balances allocated to licence cash generating units will be subject to impairment charges as the related oil and gas reserves are produced. Management's determination of the recoverable amounts of licence assets and associated goodwill requires a number of estimates and assumptions relating to operational and market factors, and involves a high degree of judgment. In addition, the calculation of recoverable amounts requires complex financial modelling of the cash flows of each cash generating unit. Significant auditor judgment is required when evaluating whether the recoverable amounts, and the assumptions which drive the underlying cash flow estimates, are reasonable and supportable.	We assessed management's identification of impairment triggers with reference to asset specific attributes and market conditions. For each cash generating unit with material asset values where a risk of impairment was identified, we critically assessed the key elements of the cash flow forecasts, including: • production profiles with reference to reserves estimates prepared by the Company's reservoir engineers and third party reserves certification reports; • three year oil and gas prices with reference to forward curve data and the Company's long term oil price assumptions against benchmark data from analysts and other publicly available sources; • opex and capex expenditures with reference to historical forecasts, approved licence budgets and management forecasts; and • abandonment expenditures with reference to our audit work on the abandonment provision (refer Abandonment provisions Key Audit Matter). In addition, KPMG valuation specialists assessed the mathematical and methodological integrity of management's impairment models, including the modelling of tax related cash flows, and assessed the reasonableness of the discount rate applied with reference to market data. We also considered whether the disclosures regarding key assumptions and sensitivities adequately reflected the underlying impairment assessments.

Abandonment provisions

Refer to financial statement Note 1.3 (Important accounting judgments, estimates and assumptions), Note 1.25 (Provisions) and Note 20 (Provision for abandonment liabilities).

The key audit matter	_How the matter was addressed in our audit_
Management's estimate of abandonment provisions requires significant judgment due to: • the technically challenging nature of the decommissioning work which may be performed over several years; • applying experiences and data from actual decommissioning projects (e.g. number of days required to plug wells) to estimates of future decommissioning activities; • uncertainties over current market costs for decommissioning work (e.g. rig rates) and future cost escalation; and • the relatively limited number of analogous decommissioning projects completed by the Company and the wider industry which can act as benchmarks.	For each licence with a potentially significant abandonment liability, we critically assessed management's estimate of the decommissioning costs, including: • well count and relevant technical details of facilities and infrastructure with reference to publicly available information and licence reporting; • assumptions for the number of days required for plugging and abandonment activities, with reference to the Company's internal benchmark data where available; • plug and abandonment costs for drilled wells, including rig costs, with reference to the Company's benchmark data;

As a result of these uncertainties, there are typically a wide range of possible abandonment provision estimates for each license. Significant auditor judgment is therefore required when evaluating the abandonment provisions, and to determine whether there is sufficient evidence available to support the estimates and judgments made.	• facilities removal and decommissioning costs with reference to the Company's internal benchmark data and third party reports where available; and • foreign currency, inflation and cost escalation assumptions with reference to market and industry data. For non-operated licences where the Company uses the operator company estimates, we assessed the amounts against reports from the operator company. In addition, we assessed the assumed economic cut-off date with reference to licence forecasts, including an assessment of the consistency with the forecasts and assumptions used in impairment testing and other audit work. We assessed the mathematical accuracy of management's discounting model to confirm the year-end present values of decommissioning cost estimates and accretion recognised during the year, and the discount rate applied with reference to industry practice along with market and Company data.

Other information

Management is responsible for the other information. The other information comprises information included in the Annual report, but does not include the financial statements and our auditor's report thereon.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Board of Directors and the Chief Executive Officer for the Financial Statements

The Board of Directors and the Chief Executive Officer (Management) are responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards as adopted by the EU, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company’s and the Group’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern. The financial statements of the Company use the going concern basis of accounting insofar as it is not likely that the enterprise will cease operations. The financial statements of the Group use the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error. We design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's or the Group's internal control.

- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's or the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company or the Group to cease to continue as a going concern.

- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with the Board of Directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit

We also provide the Board of Directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with the Board of Directors, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on Other Legal and Regulatory Requirements

Opinion on the Board of Directors' report

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Board of Directors' report including the statements on Corporate Governance and Corporate Social Responsibility concerning the financial statements, the going concern assumption, and the proposal for the allocation of the profit is consistent with the financial statements and complies with the law and regulations.

Opinion on Registration and Documentation

Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements *(ISAE) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information*, it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with the law and bookkeeping standards and practices generally accepted in Norway.

Oslo, 13 March 2019
KPMG AS

Mona I. Larsen

Mona Irene Larsen
State Authorised Public Accountant