Annual statement of reserves

2017

FOR AKER BP ASA

Table of Contents

List of Figures

List of Tables

1 Classification of Reserves and Contingent Resources

Aker BP ASA's reserves and contingent resources volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE) "Petroleum Resources Management System". This classification system is consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in Fig. 1.1.

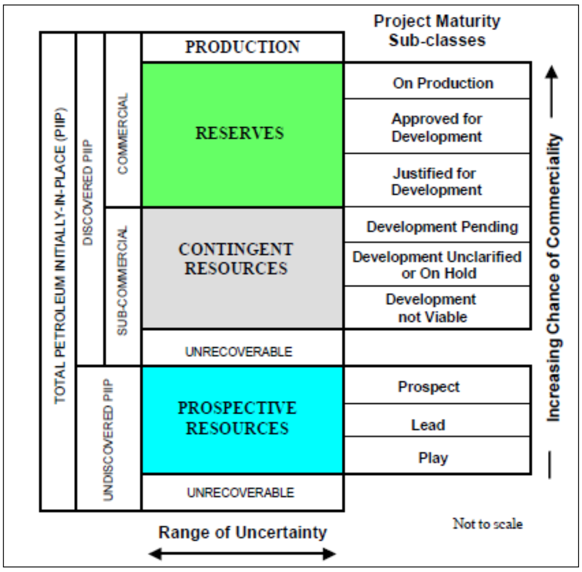

Fig. 1.1 SPE reserves and resources classification system

Note that Aker BP within this report reports Contingent Resources in the Resource classes "Development Pending" and "Development not clarified or on hold". Fig. 1.2 shows a comparison of the Norwegian Petroleum Directorate (NPD) classification system compared to the SPE system.

SPE PRMS 2007		NPD 2001		
	Project Maturity sub-classes	Resource class	Project status category	
Production		Production	S	Sold and delivered
RESERVES	On Production	RESERVES	1	In production
	Approved for Development		2 F/A	Approved PDO
	Justified for Development		3 F/A	Licencees have decided to recover
CONTINGENT RESOURCES	Development Pending	CONTINGENT RESOURCES	4 F/A	In the planning phase
	Development unclarified or on Hold		5 F/A	Recovery likely but undecided
			7 F/A	Not yet evaluated
	Development not Viable		6	Recovery not very likely
Unrecoverable				
PROSPECTIVE RESOURCES	Prospect	UNDISCOVERED RESOURCES	8	Prospect
	Lead		9	Lead and Play
	Play			

Fig. 1.2 Comparison of NPD and SPE reserves and resources classification systems

As seen from the figure also the NPD resource class 7, "Not yet evaluated", may be included in the SPE resource class "Development not clarified or on hold". Please note that Aker BP has not included any resources from NPD classes 6 or 7 in the estimates for contingent resources within this report.

2 Reserves, Developed and Non-Developed

All reserves 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 Reservoir Services, has certified all reserves except for the minor assets Atla and Enoch, representing approximately 0.004 percent of total 2P reserves.

Aker BP ASA has a working interest in 29 fields/projects containing reserves, see Table 2.1 . Out of these fields/projects, 14 are in the sub-class “On Production/Developed", 11 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 2.1 Aker BP fields containing reserves

Field/Project	Interest	Operator	Resource Class	Comment
			Developed Reserves	
Alvheim Base	65 %	Aker BP	On Production	Norwegian part, including Kameleon, Kneler and Boa. Viper/Kobra reported as separate project 2016 included
Vilje Base	46.904 %	Aker BP	On Production	
Volund Base	65 %	Aker BP	On Production	
Bøyla Base	65 %	Aker BP	On Production	
Atla Base	10 %	Total	On Production	
Ula Base	80 %	Aker BP	On Production	
Tambar Base	55 %	Aker BP	On Production	
Tambar East Base	46.2 %	Aker BP	On Production	
Valhall Base	90 %	Aker BP	On Production	
Hod Base	90 %	Aker BP	On Production	
Skarv Base	23.835 %	Aker BP	On Production	
Ivar Aasen Base	34.7862 %	Aker BP	On Production	
Gina Krog Base	3.3 %	Statoil	On Production	Production start 2017. Moved from Approved for Development
Enoch Base	2 %	Repsol Sinopec	On Production	No reserves reported in 2016 due to well integrity uncertainties
			Undeveloped Reserves	
Johan Sverdrup	11.5733 %	Statoil	Approved for Development	Includes both Phase 1 and Phase 2 (the “full field development”)
Hanz	35 %	Aker BP	Approved for Development	Included in the Ivar Aasen PDO
Alvheim Kameleon gas cap blow down	65 %	Aker BP	Approved for Development	
Alvheim Boa Infill South	57.6225 %	Aker BP	Approved for Development	Infill Well 2017/2018
Alvheim Boa Infill North	57.6225 %	Aker BP	Approved for Development	Infill Well 2017/2018
Alvheim Kameleon Infill South	65 %	Aker BP	Approved for Development	New
Valhall IP drilling programme	90 %	Aker BP	Approved for Development	Originally 7 infill wells from IP platform. Two wells drilled and included in Valhall Base
Ula WAG From Tambar & Oda	80 %	Aker BP	Approved for Development	Increased WAG efficiency on Ula due to gas import from Tambar and Oda. Replaces three separate projects in 2016 report
Tambar Development	55 %	Aker BP	Approved for Development	Includes artificial lift project in several producers in addition to two infill wells. Replaces two separate projects in 2016 report.
Skarv A-03 workover	23.835 %	Aker BP	Approved for Development	Temporarily closed well workover
Oda	15 %	Spirit Energy	Approved for Development	PDO approved - Moved from Justified for Development
Valhall Flank West Project	90 %	Aker BP	Justified for Development	PDO issued December 2017. New
Valhall North Flank Injector	90 %	Aker BP	Justified for Development	New
Ærfugl	Skarv Unit 23.835 %, PL212E 30 %	Aker BP	Justified for Development	Former Snadd - New Development. PDO issued 2017 - volumes include continuous production from well A-1H. Two phases and includes Snadd Outer in PL212E.
Skogul	65 %	Aker BP	Justified for Development	New development. PDO issued 2017

Total net proven reserves (P90/1P) as of 31.12.2017 to Aker BP are estimated at 692 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 914 million barrels of oil equivalents. The split between liquids and gas, and between the different subcategories for all fields/projects are given in Table 2.2.

Table 2.2 Aker BP 1P and 2P reserves as of 31.12.2017 per project and reserve class

1P and 2P reserves	Interest	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
per project and reserve class		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
As of 31.12.2017	%	(mmbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
On Production											
Alvheim Kameleon/Kneler	65 %	37	-	2	39	25	54	-	7	61	40
Alvheim Boa	57.6225 %	10	-	1	10	6	14	-	2	16	9
Alvheim Total		47	-	3	50	31	68	-	9	77	49
Vilje	46.904 %	14	-	0	14	7	18	-	-	18	9
Volund	65 %	16	-	1	16	11	24	-	2	26	17
Bøyla	65 %	6	-	0	7	4	9	0	0	9	6
Atla	10 %	0	0	0	0	0	0	1	0	0	0
Ula	80 %	27	1	-	28	23	39	1	-	40	32
Tambar	55 %	-	-	-	-	-	0	0	0	0	0
Tambar East	46.2 %	-	-	-	-	0	0	0	0	0	0
Valhall	90 %	103	4	15	122	110	135	5	20	160	144
Hod	90 %	3	0	0	3	3	4	0	0	4	4
Skarv	23.835 %	32	23	109	165	39	37	26	123	186	44
Ivar Aasen	34.7862 %	87	6	16	109	38	123	8	20	151	52
Gina Krog	3.3 %	75	27	48	150	5	101	37	66	204	7
Enoch	2 %	0	-	-	0	0	0	-	-	0	0.0
Total		**412**	**61**	**192**	**664**	**271**	**557**	**78**	**241**	**875**	**363**
Approved for Development											
Johan Sverdup	11.5733 %	1962	50	63	2075	240	2452	63	79	2594	300
Hanz	35 %	12	1	2	14	5	14	1	2	18	6
Alvheim Kameleon gas cap blow down	65 %	-	-	13	13	8	-	-	20	20	13
Alvheim Boa Infill South	57.6225 %	3	-	1	4	3	5	-	2	7	4
Alvheim Boa Infill North	57.6225 %	3	-	2	5	3	5	-	2	7	4
Alvheim Kameleon Infill South	65 %	3	-	0	3	2	4	-	0	5	3
Valhall IP drilling programme	90 %	42	2	6	49	44	44	2	8	54	49
Ula WAG from Tambar & Oda	80 %	9	0	-	9	7	15	0	-	15	12
Tambar Development	55 %	10	1	3	14	7	20	1	5	26	14
Oda	15 %	28	-	1	30	4	45	-	2	47	7
Skarv A-03 workover	23.835 %	-	-	-	-	-	1	1	3	4	1
Total		**2073**	**53**	**90**	**2216**	**324**	**2607**	**68**	**124**	**2798**	**415**
Justified for Development											
Ærfugl Phase 1	23.835 %	19	18	86	123	29	24	23	108	155	37
Ærfugl Phase 2 (excl. Snadd Outer)	23.835 %	6	8	38	52	12	8	10	49	67	16
Snadd Outer	30 %	2	2	10	14	4	6	8	38	52	16
Valhall Flank West Project	90 %	37	2	7	46	42	48	2	10	60	54
Valhall North Flank Injector	90 %	5	0	0	6	5	7	0	0	7	7
Skogul	65 %	6	-	1	6	4	9	-	1	10	6
Total		**75**	**30**	**142**	**247**	**97**	**101**	**44**	**206**	**352**	**136**
Total Reserves		**2559**	**145**	**423**	**3127**	**692**	**3265**	**190**	**572**	**4026**	**914**

Table 2.3 Aker BP net 1P and 2P reserves as of 31.12.2017 per field and area

1P and 2P reserves	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
per field and area	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
As of 31.12.2017	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
On Production										
Alvheim	57	-	18	75	47	83	-	33	116	73
Volund	16	-	1	16	11	24	-	2	26	17
Vilje	14	-	-	14	7	18	-	-	18	9
Bøyla	6	-	0	7	4	9	-	0	9	6
Skogul	6	-	1	6	4	9	-	1	10	6
Alvheim Area	**99**	**-**	**20**	**119**	**73**	**142**	**-**	**37**	**179**	**111**
Ula	36	1	-	37	30	53	2	-	55	44
Tambar	10	1	3	14	7	20	1	5	26	15
Tambar East	-	-	-	-	-	0	0	0	0	0
Ula Area	**47**	**2**	**3**	**51**	**37**	**74**	**3**	**5**	**82**	**59**
Valhall	187	7	29	223	201	234	10	38	282	254
Hod	3	0	0	3	3	4	0	0	4	4
Valhall Area	**190**	**7**	**29**	**226**	**204**	**238**	**10**	**38**	**286**	**257**
Ivar Aasen	87	6	16	109	38	123	**8**	**20**	**151**	**52**
Hanz	12	1	2	14	5	14	1	2	18	6
Ivar Aasen Area	**99**	**7**	**18**	**124**	**43**	**137**	**8**	**23**	**168**	**59**
Ærfugl (Including Snadd Outer)	26	28	133	188	46	37	42	195	275	69
Skarv	32	23	109	165	39	38	27	126	190	45
Skarv Area	**59**	**52**	**242**	**353**	**85**	**75**	**69**	**321**	**465**	**114**
Johan Sverdrup	**1962**	**50**	**63**	**2075**	**240**	**2452**	**63**	**79**	**2594**	**300**
Atla	0	0	0	0	0	0	1	0	0	0
Enoch	0	-	-	0	0	0	-	-	0	0
Gina Krog	75	27	48	150	5	101	**37**	66	204	7
Oda	28	-	1	30	4	45	-	2	47	7
Other	**104**	**27**	**49**	**180**	**9**	**147**	**37**	**68**	**252**	**14**
Total	**2559**	**145**	**423**	**3127**	**692**	**3265**	**190**	**572**	**4026**	**914**

An oil price of 58.0 USD/bbl (2018) and 66.6 USD/bbl (following years) has been used for reserves estimation. Sensitivities with a spread of 25 percent have also been performed. This only had a minor effect on the reserves estimates. The low price resulted in total net proven (1P/P90) reserves of 666 mmboe, and net proven plus probable (2P/P50) reserves of 902 mmboe. The high oil price resulted in 697 mmboe and 914 mmboe for proven (1P/P90) and proven plus probable (2P/P50) respectively.

Changes from the 2016 statement of reserves are summarized in Table 2.4. The main reasons for the increase in the net reserves estimate are the new Valhall development project Valhall Flank West, the new Ærfugl development project and the increased equity to 90 percent in Valhall and Hod (from 36.0 and 37.5 percent respectively).

Table 2.4 Aggregated reserves, production, developments, acquisitions, IOR, extensions and revisions

Reserves development (mmboe)	On Production		Approved for Development		Justified for Development		Total	
	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31.12.2016	**216**	**303**	**290**	**372**	**23**	**36**	**529**	**711**
Production	-58	-58			0	0	-58	-58
Transfer	25	34	-13	-11	-12	-23	0	0
Revisions	22	-1	9	-2	0	0	31	-2
IOR	0	0	9	14	0	0	9	14
Discovery and Extensions	0	0	0	0	86	123	86	123
Acquisition and sale	65	85	29	41	0	0	94	126
Balance as of 31.12.2017	**271**	**363**	**324**	**415**	**97**	**136**	**692**	**914**
Net change	**55**	**60**	**34**	**42**	**74**	**100**	**163**	**202**

Johan Sverdrup is still the most important contributor to Aker BP's reserves. After having added the new development projects mentioned above and the increased equity in Valhall and Hod, however, at the end of 2017 Johan Sverdrup accounts for 33 percent of the company's reserves, down from approximately 42 percent in 2016.

Total net production to Aker BP averaged 160 mboepd (total 58.3 mmboe) in 2017 (pro forma, reflecting 90 percent interest in Valhall and Hod).

3 Description of Reserves

3.1 Producing Assets

This chapter describes the reserves assessments for all producing fields. Please note that the 2017 produced volumes reported herein may differ slightly from volumes reported as sales volumes in quarterly reports etc. The reason is that the 2017 volumes in this report are based on actual production for the first nine months, and on forecast production for the last three months of the year. These volumes are used for assessment of remaining reserves as of 31 December 2017.

3.1.1 Alvheim (PL036, PL088BS, PL203)

Alvheim is an oil and gas field in the central part of the North Sea, west of Heimdal and near the border with the British sector. The field includes three discoveries; 24/6-2 (Kameleon reservoir), 24/6-4 (Boa reservoir) and 25/4-7 (Kneler reservoir). The Boa discovery lies partly in the British sector. Included in this chapter are also the Viper (25/4-10S) and Kobra (25/7-5) discoveries, located to the south of Alvheim just north-east of the Volund Field, Fig. 3.1. The two development wells drilled in these structures started production late 2016 and are now included in the Alvheim base reserves estimates. The water depth in the area is 120 – 130 metres.

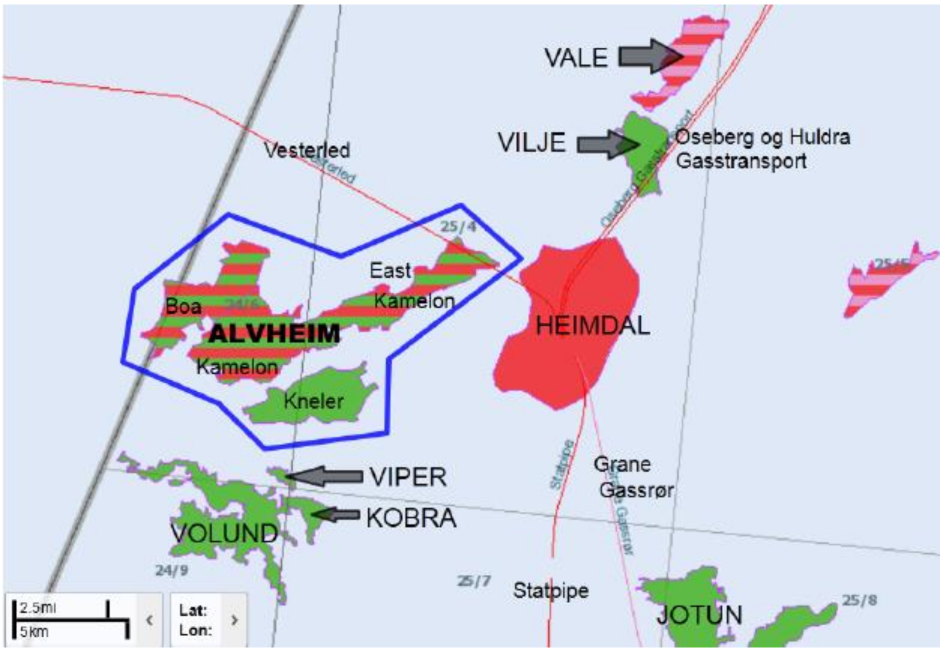

Fig. 3.1 Alvheim and Viper/Kobra location map
The Alvheim Field is divided into the Boa (partly on UK side), Kameleon and Kneler structures

Discovery

The Alvheim Field was discovered in 1998 with well 24/6-2 that encountered oil and gas in sandstones in the Heimdal Formation. The gross gas and oil columns were 52 and 17 metres respectively. The reservoir quality is generally excellent although local variations do occur. The Kobra discovery was made in 1997 with well 25/7-5 proving oil in the Hermod Formation, and the Viper discovery was made in 2009 with well 25/4-10S proving oil in Hermod Formation injection sands.

Reservoir
The Alvheim Field consists of high porosity, high permeability sandstones in the Heimdal Formation of Paleocene age. The sand was deposited as sub-marine fan deposits and lies at a depth of approximately 2,200 metres. A large number of wells, including pilot holes, have penetrated the reservoirs and confirmed the static models.

The Viper and Kobra structures are comprised of remobilized Paleocene Hermod sands with enhanced reservoir properties. Viper is an injection feature cutting through the overlying stratigraphy whilst Kobra sands are injection sands parallel to the stratigraphy with some volumes in injection features above. The development drilling campaign confirmed a common oil water contact in both structures, and it is therefore likely that Viper and Kobra communicate both in oil leg and aquifer.

Development
The Alvheim Field is developed with a production vessel, “Alvheim FPSO”, and subsea wells from five templates – Boa, Kneler A, Kneler B, East Kameleon and Volund extension. The oil is stabilised and stored on the production vessel before being exported by tanker. Processed rich gas is transported by pipeline from Alvheim to the Scottish Area Gas Evacuation (SAGE) pipeline system on the British continental shelf. Alvheim is produced through long horizontal wells completed with ICDs and several of the wells are multilateral. The recovery method is natural water drive from an active underlying aquifer.

Viper and Kobra were developed in 2016 with one horizontal well in Viper and a bilateral MLT in Kobra with one lateral in the main sill and one lateral shallower penetrating the injection dykes (Kobra shallow). The wells are tied back to a new manifold connected to the Volund extension manifold.

Status
Alvheim has produced above expectations in 2017, mainly due to the good performance of the Viper and Kobra wells. Through several periods of the year the field was constrained on gas even though the gas compressor capacity was increased in 2016. The Estimated Ultimate Recovery (EUR) has increased since the reserves certification 31.12.2016.

In May 2016 the trilateral well B5 (24/6-A-5 BoaKamNorth) started to produce from the Boa subsea manifold. The well crosses the boundary defined for the Boa and Alvheim unit areas, and reserves are split 35/65 between the Boa and Alvheim units. It was put on production with excellent results, leading to an increase in both STOIIP and EUR from the Boa and Kameleon reservoirs. Its performance has been above expectations and current WCT is around 35 percent with an oil rate around 2,200 Sm3/d. Boa well B3 (24/6-A-1) has been shut-in since reserve reporting 31.12.2016 due to swivel constraints and production optimization. Re-opening is planned in January 2019 with a low liquids rate. Also the B1 (24/6-A-3) well drilled from the Boa manifold into Kameleon remained closed due to high water cut. Two infill wells were approved for Boa in December 2016, one in the north and one with two branches in the south. These wells were drilled in the second half of 2017 and are expected to come on stream early 2018.

Production from Viper and Kobra started in November 2016. Both Viper and Kobra came in close to expectations. Additional volumes in injectites above the main Kobra sand were proved by drilling. Production performance in 2017 has been above expectation, both due to optimization within the Volund pipeline and delayed water breakthrough in both accumulations.

The East Kameleon well EK2 is producing at higher GOR than expected, resulting in frequent shut-ins due to production optimization and reservoir management strategy. Several other wells in Kneler and Kameleon are shut in at times for reservoir management and production optimisation purposes.

Total number of wells drilled on Alvheim by the end of 2017 is 20. Only the B1 (24/6-A-3) well has no remaining reserves associated.

Kameleon Infill South was approved internally Q4 2017. This well targets remaining attic and flank oil in the south-western area of the Kameleon field through a tri-lateral.The recoverable volumes for Alvheim, Viper and Kobra are classified as "Reserves; On Production" (SPE's classification system).

Net production from Alvheim, including Boa and Viper/Kobra, averaged 53.4 mboepd in 2017 which is approximately 23 percent above forecasted volumes. This was mainly caused by the good performance and production optimization of Viper/Kobra.

Production from the Alvheim Field is expected to cease in 2033, with subsequent abandonment scheduled to take place between 2033 and 2035.

Aker BP is the operator of the Alvheim Area Fields with a 65% working interest in the Norwegian parts. The other partners are ConocoPhillips Skandinavia AS holding a 20% interest and Lundin Norway AS holding a 15% interest.

The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitized with Verus Petroleum, who is the sole owner on the UK side after acquiring Maersk Oil & Gas share. Aker BP's interest in the Boa unit is 57.62%.

3.1.2 Vilje (PL036D)

The Vilje Field is and oil field located 5 kilometres north-east of the Heimdal production facility in block 25/4 licensed under PL036D in the North Sea, see. Fig. 3.2. Production started in 2008. The reservoir depth is about 2,200 metres TVD MSL and the water depth in the area is approximately 120 metres.

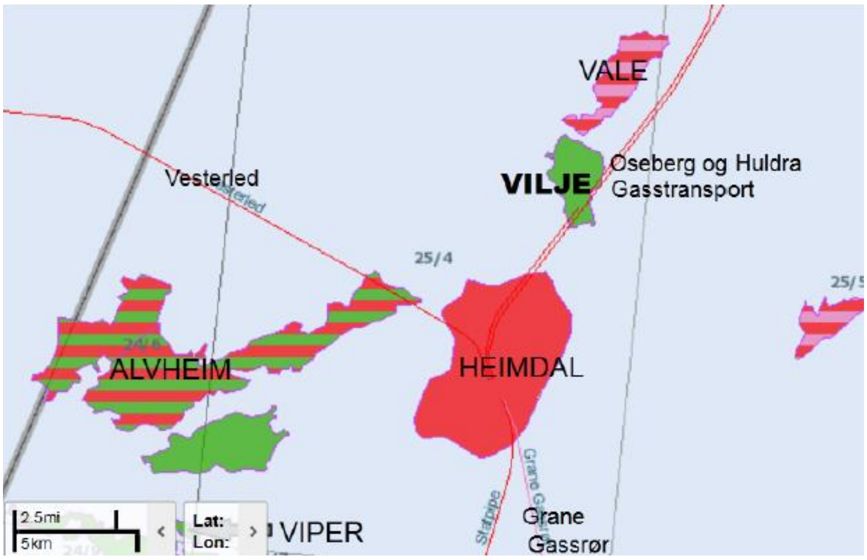

Fig. 3.2 Vilje location map

Discovery
The Vilje Field was discovered in 2003 by well 25/4-9 S. The Heimdal Formation reservoir was encountered at 2135 metres TVD MSL with 61 metres gross sand (56 metres net). The sand has very good reservoir properties and was oil bearing with under-saturated oil. Production from the nearby Heimdal Field and Frigg Field had caused depletion of the regional aquifer by approximately 18 bars. Based on the well results the OWC has been determined at various levels between 2,195 and 2,198 metres TVD MSL, and the current OWC is expected to be influenced locally by depletion and production.

Reservoir
The Vilje Field is a flat low-relief fan of Heimdal depositional system. The field has two more or less separate structures, namely Vilje Main and Vilje South. The reservoir is a turbidite deposit, in the Heimdal Formation of Paleocene age at about 2,150 metres TVD MSL. The reservoir interval is divided into three reservoir zones – R1, R2 and R3 – whereof R1 and R3 are clean sands while R2 is a fine-grained muddy layer which is acting as a baffle to fluid flow.

Development
The Vilje Field is a subsea development with three subsea horizontal producers tied back to the Alvheim FPSO. Vilje Main is drained by one single lateral well (VI1) and one bilateral well (VI2) with one branch above and one below the R2 shale. There is one single lateral well on Vilje South (VI3). The water depth in the area is approximately 120 metres. The recovery mechanism is natural water drive from the regional underlying Heimdal aquifer.

Status
Plateau oil production was 5,000-6,000 Sm3/d until July 2012. Water breakthrough occurred in July 2011 and currently the oil rate is around 2,000 Sm3/d. The lower branch in well VI2 was shut-in in 2011 and was reopened in April 2016, increasing the production rate. The upper branch of VI2 was shut-in from July 2016. Originally it was planned to re-open the upper branch in November 2016 to increase production, but this is postponed to mid 2018 due to good performance of the lower branch. The upper branch will be re-opened once water cut of the lower branch has reached 85 percent. Producing with a low draw down seems to be the key factor to stabilize water cut development in the lower branch. VI3 produced for one month in May 2017. The water cut development in this well is very sensitive to gas lift/draw-down development. In January 2018 it is planned to reopen VI3 to give enough time to produce the reserves before Skogul will be tied in to Vilje. A new reservoir model is planned to be generated in 2018 based on 4D seismic.

The total number of producers drilled on Vilje is 3. All three wells have produced in 2017.

The recoverable volumes for Vilje are classified as "Reserves; On Production" (SPE's classification system).

Net production from Vilje averaged 5.3 mboepd in 2016 which is approximately 10 percent above prognosed volume. The reason for this is improved performance from VI1 and VI2 lower branch with a slower water cut development.

Production from the Vilje field is expected to cease in 2033, with subsequent abandonment scheduled to take place between 2033 and 2035, which coincides with the expected cessation of production from the Alvheim area.

Aker BP holds a 46.904% interest in the license and serves as operator. The other license partners are Statoil Petroleum AS holding a 28.853% interest and PGNiG Norge with a 24.243% interest.

3.1.3 Volund (PL150)

The Volund Field is an oil field located 8 kilometres south of the Alvheim Field in block 24/9 in the North Sea. The reservoir depth is about 1,900 metres TVD MSL and the water depth in the area is about 120-130 metres. Production started in April 2010. Fig. 3.3 shows the location of the asset.

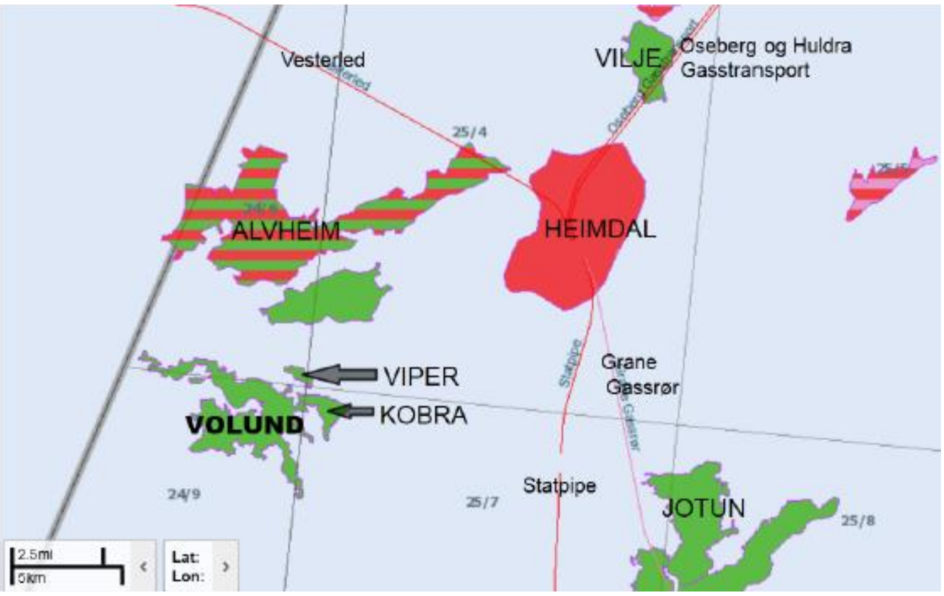

Fig. 3.3 Volund location map

Discovery
Volund Field was discovered in 1994 by well 24/9-5. The Intra Balder Formation sandstones were encountered with oil in the interval 2,011 to 2,018 metres TVD MSL (oil down to). The discovery was appraised by wells 24/9-6 and 24/9-7, confirming a field wide OWC of 1995 metres TVD MSL and a GOC of 1,891 metres TVD MSL.

Reservoir
Volund is a massive injectite complex consisting of high quality, Darcy sands which have been injected from early Eocene Hermod Formation into overlying shales of the Sele, Balder and Hordaland formations. Dykes, termed “wings”, rise in 3 directions from a central lower sill which is mainly situated below the OWC. This results in a “bathtub” shape open to the west. Volund is unique in the sense that the entire hydrocarbon accumulation is contained in injected sands and with the majority within cross-cutting dykes.

Development
The field is developed as a subsea tie-back to the nearby production vessel, Alvheim FPSO. Initial development included three producing wells targeting the ~100 metres oil column in the wings supported by one water injector in the sill in addition to natural water drive. The first infill well started production in 2013. Another two infill wells started production in 2017.

Status
In 2017, two infill wells started production as planned over the summer and these have delivered good initial rates. The 24/9-P-9 well targeted an undrained sill in the western part of the field while

the tri-lateral 24/9-P-10 well targeted attic oil above the 24/9-P-2 well as well as undrained dykes in the southern area of the field. The wells share the manifold with the Viper/Kobra wells.

One of the four mature oil producers at Volund (24/9-P-5) remains shut in due to high GOR and water cut. During 2017 the other three mature producers at Volund were kept closed for production optimization allowing capacity in the pipeline for Viper/Kobra production and the new Volund producers coming on stream. The water injector is injecting at 60 percent voidage which has proved to be enough for pressure maintenance.

Total number of wells drilled on Volund is 6. All wells except for 24/9-P-5 have associated reserves.

The recoverable volumes of Volund are classified as "Reserves; On Production" (SPE's classification system).

Net production at Volund averaged 5.1 mboepd in 2017 which was marginally below prognosed volume. The main reason was the production optimisation in favour of the Viper/Kobra wells which resulted in all Volund production shut in in the first half of 2017.

Cessation of production from the Volund field is expected in 2033.

Aker BP holds a 65% interest in Volund and serve as operator, while Lundin Norway AS holds the remaining 35% interest.

3.1.4 Bøyla (PL340)

The Bøyla Field is an oil field located in PL340, block 24/9 in the central part of the North Sea 15 kilometres south-west of the Volund Field. The water depth is 120 metres and the depth of the reservoir is 2,000 metres TVD MSL. Well M-01 BH, on the north western flank, started to produce in January 2016 and is the main contributor. The location of the Bøyla Field is shown in Fig. 3.4.

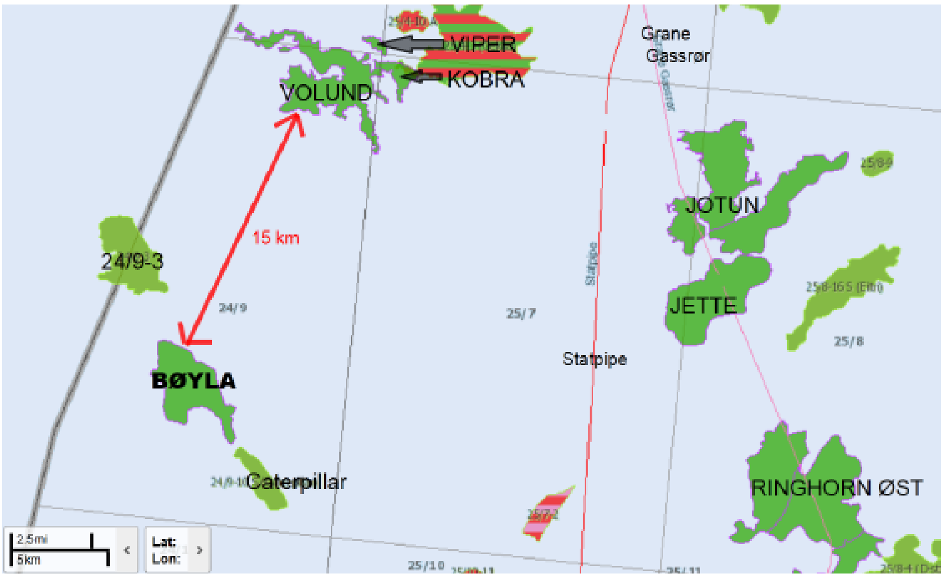

Fig. 3.4 Bøyla location map

Discovery
The Bøyla Field was discovered in 2009 by well 24/9-9 S. The initial discovery name was "Marihøne A". The well proved under-saturated oil at normal pressure with a OWC at 2,071 metres

TVD MSL. Subsequent pilot and development wells have confirmed the OWC across the field. Bøyla started to produce in January 2015.

Reservoir
The Bøyla structure is a flat low-relief Eocene fan deposit. The reservoir of the field is within the Paleocene/Eocene Hermod Sandstone Member, completely encased within Sele Formation shales. The Hermod Sandstone Member is interpreted as sediment gravity flows sourced from the East Shetland Platform, depositing in a basin floor setting. Hermod sandstones are assumed to have filled bathymetric lows created by underlying Heimdal member.

Two major depocenters have been recognised in the field, one in the west, and one in the east with uncertainty around the connectivity between these two parts of the reservoir. The pre-drilled wells confirmed a consistent OWC. Injection testing of the single water injector has proved enough injectivity and interference between the injector (M3) and the western producer (M1). Production experience shows that communication between the injector and the eastern producer (M2) is not likely.

Development
The field is a subsea development with two long horizontal producers (about 2,300 metres) and one water injector tied back to the Alvheim Field some 28 kilometres to the North via the Kneler A manifold. Gas lift is required in the producers.

Status
The performance from well M1 (01 BH) is still good even though the water cut has increased from around 20 percent in 2016 to 45 percent in 2017. Injector M3 (03 AH) started in March 2015, and the second producer on the south eastern flank M2 (02 HT3), started in August 2015. No communication with the water injector is observed, but the injector ensures voidage replacement for M1 even though the injectivity has proven to be lower than expected.

During 2 periods in 2017 the M2 well has been shut-in and gas was injected into the reservoir through the gaslift line to increase the pressure around the wellbore and stabilise production. The effects of this injection have been positive and further cycles are planned going forward.

Total production wells drilled on Bøyla is 2. Both wells have associated reserves.

The recoverable volumes of Bøyla are classified as "Reserves; On Production" (SPE's classification system).

Net production at Bøyla averaged 4.5 mboepd in 2017 which was almost 20 percent below prognosed volumes due to the shut-in of M2 during large periods of the year. Cessation of production from the Bøyla field is expected in 2033 together with abandonment activities relating to the other Alvheim Area fields.

Aker BP, as operator, holds a 65% interest in Bøyla. Point Energy AS holds a 20% interest and Lundin Norway AS holds the remaining 15%.

3.1.5 Atla (PL102C)

Atla is a small gas/condensate field in the central part of the North Sea in a water depth of 119 metres.

Discovery
The Atla Field was discovered in 2010 by well 25/5-7.

Reservoir
The reservoir contains gas/condensate in sandstones in the Brent Group of Middle Jurassic age at a depth of about 2,700 metres.

Development
The field produces with a subsea installation tied back to the existing pipeline between the Heimdal and Skirne fields. Production started two years after the discovery in October 2010.

Status
Atla physical production is predicted to cease in 2017. The proved (1P/P90) and proved plus probable (2P/P50) reserve estimates reflect Skirne compensation of gas and condensate to Atla. The base 2P/P50 case considers two months of Atla production in 2017, which means two months without condensate transfer from Skirne. The volumes not transferred in 2017 will be transferred in 2018 instead. Skirne gas transfer to Atla can be performed while the two fields are producing simultaneously.

Net production from Atla averaged 0.1 mboepd in 2017.

Aker BP holds a 10% interest in the license. Total E&P Norge AS is the operator holding a 40% interest while Petoro AS holds a 30% interest and Lotos Exploration and Production Norge AS holds the remaining 20% interest.

3.1.6 Ivar Aasen and Hanz (PL001B, PL028B, PL242, PL338BS, PL457)

The Ivar Aasen field is located in the North Sea 8 kilometres north of the Edvard Grieg Field, and around 30 kilometres south of Grane and Balder. The field contains both oil and free gas. The Ivar Aasen field includes two accumulations; Ivar Aasen and West Cable, Fig. 3.5. The accumulations cover several licences and have been unitized into the Ivar Aasen Unit. The water depth in the area is approximately 110 metres and the main reservoir at Ivar Aasen is found at around 2,400 metres TVD MSL reservoir depth.

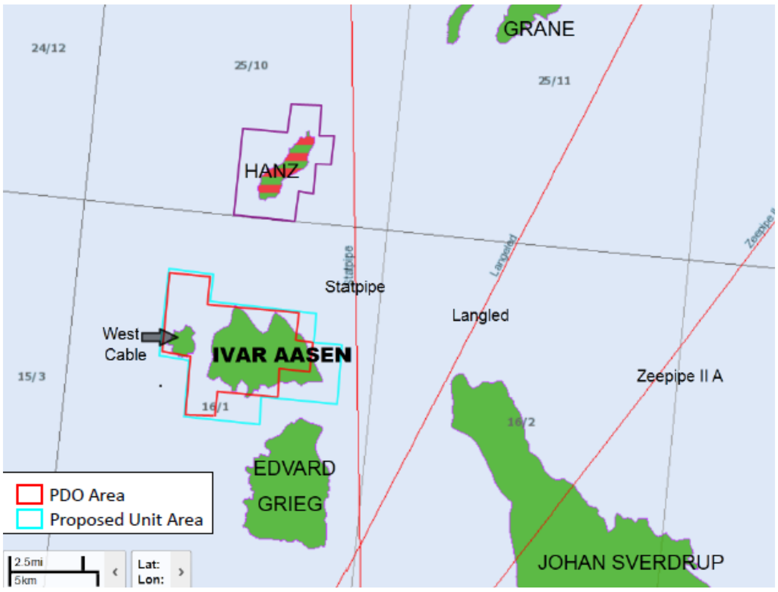

Fig. 3.5 Ivar Aasen Unit and Hanz location map

Discovery
Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones. An earlier exploration well 16/1-2 in 1976 within the structural closure was initially classified as dry, but was after a re-examination re-classified as an oil discovery. West Cable was discovered with well 16/1-7 in 2004, proving oil in Jurassic sandstones.

Reservoir
The two accumulations are located at the Gudrun Terrace between the Southern Viking Graben and the Utsira High. The reservoir sands are fluvial and shallow marine deposits of late Triassic to late Jurassic age. The reservoir sands in the Ivar Aasen structure are complex and heterogeneous while the reservoir at West Cable is more homogeneous. The Ivar Aasen structure contains saturated oil and two gas caps while the West Cable structure contains under-saturated oil.

Development
The drainage strategy for the Ivar Aasen structure assumes water injection for pressure maintenance. West Cable will be produced by natural depletion where the major driving force is aquifer drive. In total seven producers (six targeting the Ivar Aasen structure and one in West Cable) and six water injectors (in the Ivar Aasen structure) have been drilled in the field. The production wells are completed with mechanical sand control and ICD completions while the injectors have cemented perforated liners. In Phase 2 of the development, the Hanz discovery will be developed with two subsea wells tied back to the Ivar Aasen platform.

The field is developed with a steel jacket including living quarters and process facilities located at a water depth of 110 metres with dry well heads on the platform. The wells are drilled from a jack-up rig. The well stream is partly processed on the platform before transportation through pipelines to the Edvard Grieg installation for final stabilization and export. Edvard Grieg also covers Ivar Aasen's power demand until a joint solution for power from shore is established.

Status
The PDO for the Ivar Aasen area was approved early 2013. The field development went according to plan and the field came on production 24 December 2016.

All initially planned wells have been drilled in the Ivar Aasen and West Cable structures. The development wells on Ivar Aasen Main Field came in roughly as expected. The first development well in West Cable was disappointing as top reservoir came in deeper than expected. The side track on West Cable was successful with penetration of oil filled reservoir sands.

The production of Ivar Aasen has been as expected for 2017, and the field is producing with good efficiency. However, the field is experiencing injection challenges and voidage replacement with water has been a challenge especially for the eastern part of the Ivar Aasen Main Field. The injection challenges have been partly due to completion leakages (now repaired) and partly due to lower injectivity in Skagerrak 2 than expected. Aker BP will mitigate this by drilling two new injection wells in 2018 with expected start-up in May 2018.

The recoverable volumes of Ivar Aasen are classified as "Reserves; On Production" (SPE's classification system).

Net production at Ivar Aasen averaged 6.6 mboepd in 2017 which is in line with prognosed volumes. Cessation of production from the Ivar Aasen field is expected in 2034.

Aker BP holds a 34.7862% interest in the unit. The other licensees are Statoil Petroleum AS (41.4730), Bayerngas Norge AS (12.3173%), Wintershall Norge AS (6.4615%), VNG Norge AS (2.0230%), Lundin Norway AS (1.3850%) and OKEA (Norge) AS (0.5540%).

3.1.7 Valhall (PL006B, PL033B)

Valhall is an oil field in the southern part of the Norwegian sector of the North Sea in PL006B and PL033B (unitized into the Valhall Unit) in blocks 2/8 and 2/11, Fig. 3.6. The water depth is about 70 metres.

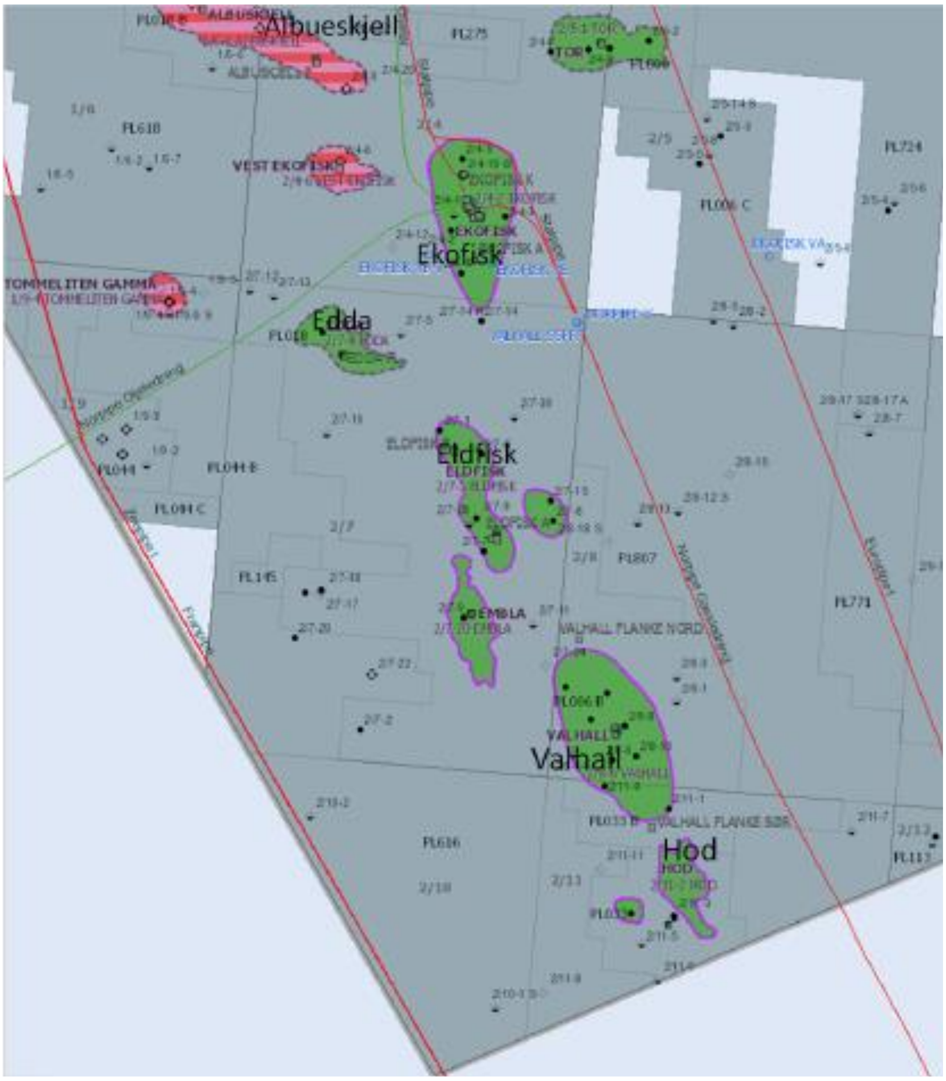

Fig. 3.6 Valhall and Hod location map

Discovery
The Valhall Field was discovered in 1975 by exploration well 2/8-6. Production started in 1982.

Reservoir
The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2,400 metres. The Tor Formation chalk is fine-grained and soft; with high porosity (up to 50 percent). Matrix permeability is in the 1-10mD range. There are areas with natural fractures with high permeability conduits. The Hod Formation porosity is 30-38 percent with permeability 0.1-1mD.

The Valhall Field is subdivided into 8 reservoir units: (a) North Flank, (b) Northern Basin, (c) East Flank, (d) West Flank, (e) South Flank, (f) Central Crest, (g) Southern Crest, (h) Lower Hod Formation. Seven of the units are areally distributed within the Tor formation. The eighth unit is in the underlying Lower Hod formation.

The field has produced with pressure depletion and a very effective compaction drive since 1982. As a result of the pressure depletion the chalk has compacted and the seabed subsided. Water injection in the centre of the field started in 2004. This has reduced pressure depletion and hence subsidence. Gas lift is used to optimise production in most of the producers as a remedy to avoid oscillating production and premature dying of wells.

Development

The plan for development and operation (PDO) for Valhall was approved in 1977. The field was originally developed with three platforms; accommodation, drilling and processing. The PDO for a Valhall wellhead platform was approved in 1995, and the platform (WP) was installed in 1996. A PDO for a water injection project was approved in 2000, and an injection platform (IP) was installed in 2003. Bridges connect the platforms. A sixth platform (Flank West) was sanctioned in 2017 which added considerable reserves to the field.

Oil and NGL are routed via pipeline to Ekofisk and further to Teesside in the UK. Gas is sent via Norpipe to Emden in Germany.

Status

Valhall is currently producing from 48 producer and 6 active injectors. Gas lift has now been installed on most of the Valhall producers.

Two wells have been completed in 2017 out of the 2016 sanctioned 7 well IP drilling programme. The remaining five IP wells will be drilled and completed throughout 2018 and 2019.

The Valhall Flank West project was sanctioned and a PDO submitted December 2017. The project consists of an unmanned 12-slot wellhead platform tied back to the Valhall PH platform. 6 wells are planned to be drilled with start-up and first production in 2019.

Two producers in the Northern Basin (N-14 and N-15) were shut in during 2017 and are likely to remain shut-in for another year to allow re-pressurisation of the area. Furthermore the North Flank Water Injection project (NFWI) has been matured and sanctioned internally whereas JV approval is expected in early 2018. This includes a water injection line from the field centre to the North Flank platform as well as one water injector to be drilled and completed in the Northern Basin (2020).

The recoverable volumes for Valhall are classified as "Reserves; On Production" for Base, "Approved for Development" for IP drilling programme and "Justified for Development" for the North Flank Water Injection project and Flank West Development Projects (SPE's classification system).

The 2P/P50 production profile indicates an economic cut-off in 2042.

Net production to Aker BP averaged 33.7 mboepd in 2017 (pro forma, reflecting 90% Aker BP net equity). This was about 8 percent below plan. The difference can be explained by the decision to keep N-14 & N-15 shut-in through 2017 in order to build pressure for drilling of new injector in this basin (North Flank Injection Project). This was part of the 2017 production plan submitted in 4Q 2016.

After the acquisition of Hess Norge AS and the sale of a 10% interest to Pandion Energy in 2017, Aker BP holds a 90% interest in the Valhall Unit.

3.1.8 Hod (PL033)

Hod is an oil field 13 kilometres south of the Valhall Field in the southern part of the Norwegian sector in the North Sea (PL033 in block 2/11), Fig. 4.13. The water depth is approximately 70 metres and the reservoir depth is about 2,700 metres TVD MSL. The location of Hod is shown in Fig. 3.6.

Discovery
The Hod Field was discovered in 1974 by exploration well 2/11-2. Production started in 1990.

Reservoir
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 consists of three structures: Hod Vest, Hod Øst and Hod Saddle. The field is produced by pressure depletion. Gas lift has been used in some wells to increase production.

Development
The field was initially developed with an unmanned production wellhead platform which was remotely controlled from Valhall. There has, however been no production from the Hod facility since 2012. The Hod Sadel, which connects the Hod and Valhall reservoirs is currently produced through four wells drilled from Valhall. The Hod facility awaits decommissioning and disposal.

Transport of oil and NGL from Valhall is routed via pipeline to Ekofisk and further to Teesside in the UK. Gas from Valhall is sent via Norpipe to Emden in Germany.

Status
A total of 12 wells has been drilled on the field of which four are currently producing. There has been no production from the Hod facility since 2012 and the four producing wells are drilled from the Valhall South Flank platform and part of these wells extend into the Hod license. The equity split (between Valhall and Hod license) is based on 'length of well' in respective licenses. The allocated production rate to the Hod field is in the range of 1,500 boepd with a gentle decline towards 2035 (expected life time of Hod Saddle wells).

Net production to Aker BP averaged 1.3 mboepd in 2017 (pro forma, reflecting 90% Aker BP net interest).

After the acquisition of Hess Norge AS and the sale of a 10% interest to Pandion Energy in 2017, Aker BP holds a 90% interest in Hod.

3.1.9 Ula (PL019)

Ula is an oil field in the southern part of the Norwegian sector of the North Sea in block 7/12 in PL019, Fig. 3.7. The water depth in the area is about 70 metres and the reservoir depth is about 3,500 metres TVD MSL.

Fig. 3.7 Ula location map

Discovery

Ula was discovered by well 7/12-2 in 1976. The well penetrated a major Late Jurassic reservoir (Ula Formation) and was terminated within a Triassic hydrocarbon bearing sequence of poor quality sands and interbedded shales. Core analysis and log interpretation indicate an Ula Formation sandstone reservoir, of 128 metres net thickness with porosities ranging from 14 to 28 percent, permeabilities from a few mD to over 2 D and water saturations from 5 to more than 50 percent. The Ula Formation was oil bearing from top to base at 3,532 metres in an oil down-to setting.

Development

The Ula development consists of three conventional steel facilities for production, drilling and accommodation, which are connected by bridges. The gas capacity at Ula was upgraded in 2008 with a new gas processing and gas injection module (UGU) that doubled the capacity. Ula is the processing facility for Tambar, Blane and Oselvar, and will also be the processing facility for nearby Oda development. The oil is transported by pipeline via Ekofisk to Teesside in the UK. All gas is re-injected into the reservoir to increase oil recovery.

Reservoir

The main reservoir is at a depth of 3,345 metres in the Upper Jurassic Ula Formation. The Jurassic reservoir consists of two production intervals with water and gas injection in the deeper layer. A separate Triassic reservoir underlies the main reservoir. Oil was initially recovered by pressure depletion, but after some years, water injection was implemented to improve recovery. Water alternating gas (WAG) injection started in 1998. The WAG programme has been extended with gas from Tambar (2001), Blane (2007) and Oselvar (2012). Gas lift is used in the shallowest reservoir interval.

Status
42 wells have been drilled on Ula since start-up of which 6 wells are currently producing and 4 are injecting.

Based on the positive experiences with WAG effect on oil recovery, gradually more WAG wells are planned. In 2016, the partnership in production licence 405 decided to develop the 8/10-4 S discovery (Oda) as a tie-in to Ula and a PDO was issued November 2016. Gas from Oda will be injected into the Ula reservoir to increase recovery. In addition associated gas from the Tambar gas lift project and two new Tambar infill wells will be injected in Ula.

Injection of additional import gas from Oda and Tambar will increase reserves. The reserves from these future projects are classified as Undeveloped Reserves. In addition several non sanctioned planned infill wells will probably increase the reserves on Ula.

The 2P/P50 production profile indicates an economic cut-off in 2034.

Net production to Aker BP averaged approximately 6.8 mboepd in 2017. This was approximately 5 percent below forecast due to poorer WAG response.

Aker BP is the operator and holds 80% interest in the Ula Field. The remaining 20% interest is held by Faroe Petroleum Norge AS.

3.1.10 Tambar (PL065)

Tambar is an oil field about 16 kilometres south-east of the Ula Field in the southern part of the Norwegian sector of the North Sea, Fig. 3.8. The water depth in the area is 68 metres.

Fig. 3.8 Tambar and Tambar East location map

Discovery
Tambar was discovered in 1983 by well 1/3-3.

Reservoir
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 and the reservoir characteristics are generally very good. The field is produced by pressure depletion, with natural gas expansion combined with aquifer support as the main reservoir drive mechanisms.

Development
The field has been developed with a remotely controlled wellhead facility without processing equipment. The oil is transported to Ula through a pipeline. After processing at Ula, the oil is exported in the existing pipeline system via Ekofisk to Teesside in the UK, while the gas is injected into the Ula reservoir to improve oil recovery.

Status
A total of three producers have been drilled on Tambar since start-up of which one well is currently producing.

Major challenges restricting production are wells that die and increasing water-cut. Recently, a 4D seismic survey has been carried out to enhance reservoir management. There is special focus on well surveillance, as well as on the evaluation of IOR options, such as infill drilling and gas lift in existing wells. As a result of this Tambar Infill South (IFS), Tambar Infill North (IFN) and Tambar Artificial Lift (TAL) (the Tambar Development Project) was sanctioned in 2016/2017. Both wells are close to completed and will commence production in Q1 2018.

The recoverable volumes of Tambar Area are classified as "Reserves; On Production" and "Reserves; Approved for Development (SPE's classification system).

Net 2017 production to Aker BP from Tambar and Tambar East averaged approximately 2.0 mboepd. This was approximately 5 percent below forecast.

Aker BP is the operator and holds 55% interest in the Tambar Field. The remaining 45% interest is held by Faroe Petroleum Norge AS.

3.1.11 Tambar East (PL065, PL300, PL019B)

Tambar East is a minor oil field located east of Tambar, see Fig. 3.8

Discovery
Tambar East was discovered in 2007 by well 1/3-K-5.

Reservoir
The reservoir consists of sandstones of Late Jurassic age, deposited in a shallow marine environment. The reservoir lies at a depth of 4,050-4,200 metres and the quality varies, but is generally poorer than the Tambar main field. The field is produced by pressure depletion, and the reservoir is believed to be compartmentalized.

Development
Tambar East is an oil field in the North Sea developed with one production well drilled from the Tambar facility. The field location is shown in Fig. 6.2. The oil is transported to Ula via Tambar.

After processing at Ula, the oil is exported in the existing pipeline system via Ekofisk to Teesside in the UK. The gas is used for gas injection in the Ula reservoir to improve oil recovery.

Status
In the previous RNB submission cessation of production was assumed in 2017. The well was temporarily shut down in November 2017 and the assumptions is that well K-5A will be restarted in 2024 when back pressure has declined and local reservoir pressure has increased.

The recoverable volumes of Tambar are classified as "Reserves; On Production" (SPE's classification system).

Aker BP is the operator and holds 46.2% interest in the Tambar East Unit. The remaining interests are held by Faroe Petroleum Norge AS (37.8%), Repsol Norge AS (9.76%), INEOS E&P Norge AS (5.44%) and KUFPEC Norway AS (0.80%).

3.1.12 Skarv (PL262, PL159, PL212B, PL212)

Skarv/Idun is an oil and gas field located about 35 kilometres south-west of the Norne Field in the northern part of the Norwegian Sea in the Skarv Unit in blocks 6507/2, 6507/3, 6507/5 and 6507/6. The water depth in the area is 350-450 metres, Fig. 3.9. The Skarv unit is a joint development of the Skarv, Idun and Ærfugl fields (former Snadd, see 3.2.3 Ærfugl (Skarv Unit, PL212E)). Note that the northern part of the Ærfugl discovery is not a part of the Skarv Unit, Fig. 3.9

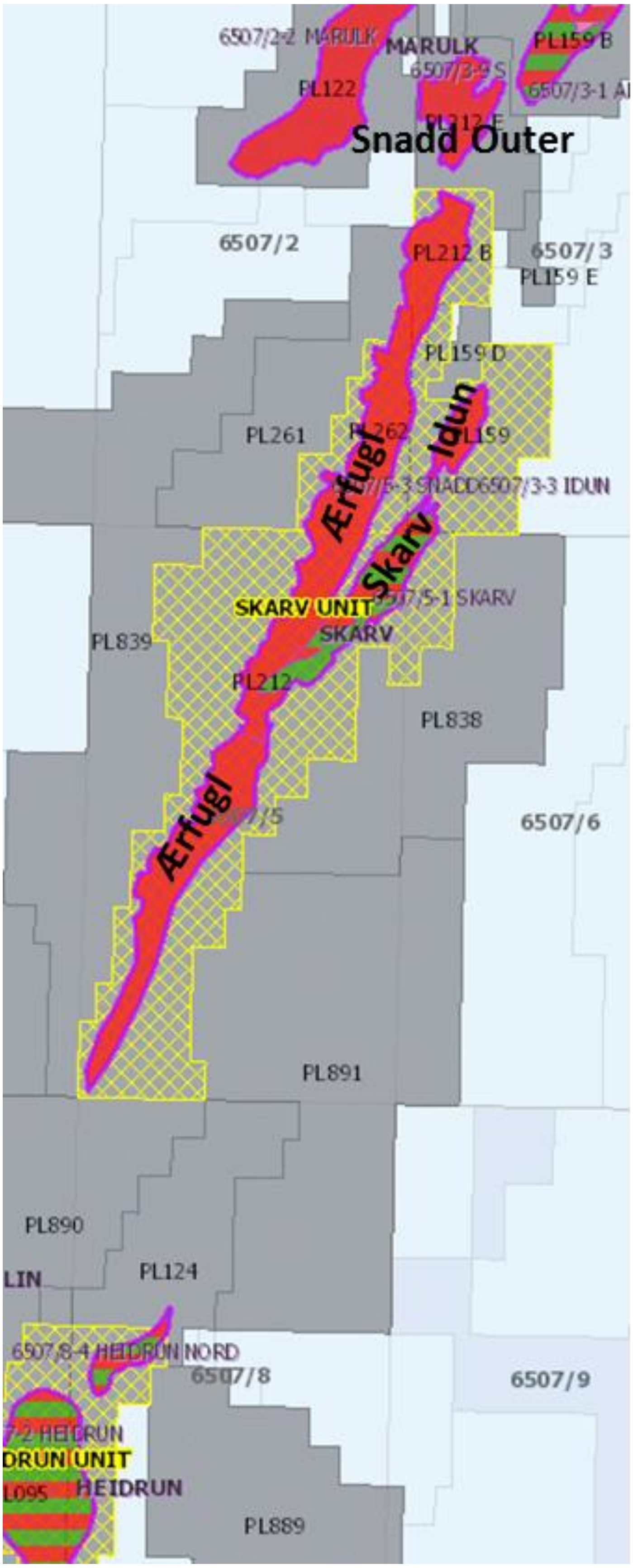

Fig. 3.9 Skarv and Snadd location map.

Discovery
Gas in the segment Skarv A was discovered by 6507/5-1 in 1998. Later the field was appraised and gas with an oil column was found in the Skarv B and C segments. Dry gas in Idun north of Skarv was discovered by well 6507/3-3 in 1999.

Development
The development concept is a production, storage and offloading vessel (FPSO) above the Skarv Field tied to five subsea templates with fifteen wells. Distribution between the well types are: 6 oil producers, 5 gas producers, 4 gas injectors and 1 Ærfugl test well (addressed in chapter 3.2.3 Ærfugl (Skarv Unit, PL212E)).

The oil is exported by shuttle tanker. The gas is exported in an 80 kilometres pipeline connected to the Åsgard Transport System. Capacity in Gassled is secured through the Gassco booking system.

Reservoir
The Skarv structure is defined by three segments, named the A, B and C segments, which are separated by sealing faults. However, production experience shows that the fault between B and C segment may be leaking. Idun (East and West) is a separate, gas filled structure. The segments are close to hydrostatic pressure. Each segment constitutes of Jurassic Garn, Ile and Tilje formations. The Garn Formation is a high quality reservoir and the deeper Ile and Tilje formations are more heterogeneous with poorer reservoir quality.

Skarv/Idun Field contains both oil and gas. The production strategy is oil production in combination with gas injection, keeping the pressure constant, followed by gas blowdown. The gas filled segments are produced by depletion.

Status
Skarv/Idun production started 31 December 2012. Current daily production is close to 16,000 Sm3 o.e. To date approximately half of the estimated ultimate recovery is produced. Four gas wells are currently producing, two in Garn A and two in Idun. They are all on decline. The two oil wells in Tilje Formation in the A segment have been producing with a stable rate throughout 2017. During spring/summer 2017 both the oil producers (B06 and B08) in the B segment got problems with the Christmas tree. B08 was worked over and brought back on stream in December 2017. Well B06 is scheduled for a workover during the first half of 2018. The oil wells in the B and C segment are on decline, and have all had gas breakthrough from supporting gas injectors.

The western Idun well, D02, is the only well that has water production. The water production rate has declined and the well has seen no lifting issues and little impact on gas production. It is likely that the water is coming from an underlying sand that depleted rather than from the main production targets.

The estimated future production is solely based on current oil and gas producers, and thus falls within the PRMS definition for reserves. The recoverable volumes of Skarv are classified as "Reserves; On Production" (SPE's classification system).

The Skarv unit submitted a Plan for Development and Operation (PDO) for the Ærfugl Field in December 2017, see chapter 3.2.3 Ærfugl (Skarv Unit, PL212E).

Aker BP is the operator and holds a 23.835% interest in the Skarv Unit. The remaining interests are held by Statoil Petroleum AS (36.165%), DEA Norge AS (28.0825%) and PGNiG Upstream International AS (11.9175%).

3.1.13 Gina Krog (PL029B)

The Gina Krog oil and gas field is situated in the south-eastern end of the Viking Graben at the north-western extension of the Sleipner Terrace, directly north of the Sleipner Vest Alfa Nord segment, Fig. 3.10. The water depth is 120 metres. Statoil is the operator, and a unit agreement is signed covering the licences PL048, PL029C, PL029B and PL303.

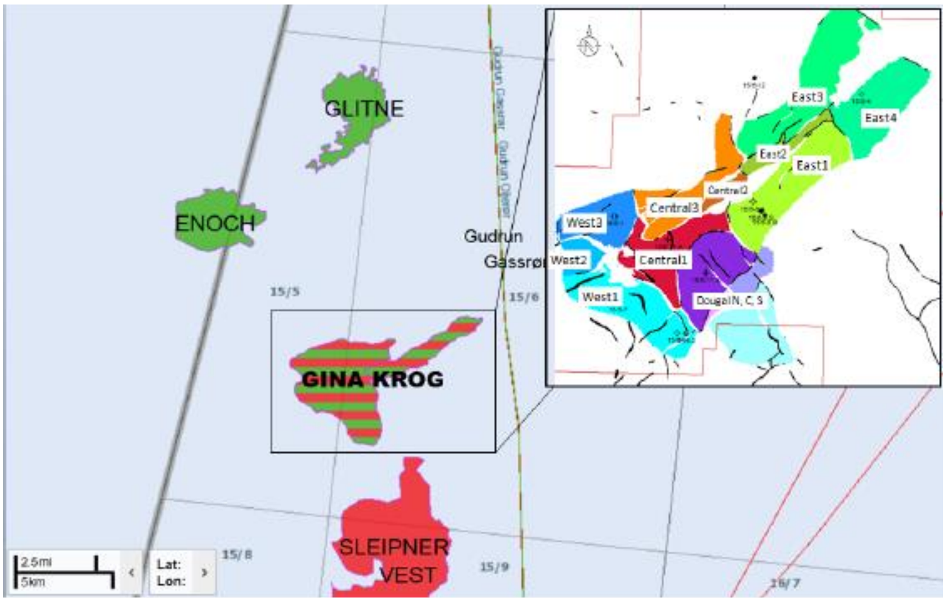

Fig. 3.10 Gina Krog location map.

Discovery
Gina Krog, (segment West), was discovered in 1974 with shows in well 15/6-2 R, and in 1977 the well 15/5-1 confirmed gas/condensate. Later appraisal wells proved oil in West, gas with an oil leg in East and gas within the Central part of the field. Gina Krog is a complex field with 14 faulted segments, where five are referred to as reference segments and are included in the reserves estimate. These are West 1, West 2, West 3, Central 1 and East 1. Discoveries are also made in some other segments. These, are however, not included in the reserves. There are variations in both fluid properties and fluid contacts over the field.

The structure has steep flanks and a large hydrocarbon column of approximately 600 metres.

Reservoir
The reservoir comprises sandstones of the Hugin Formation (Callovian, Middle Jurassic) with moderate to poor reservoir quality at depth of 3,300 - 3,900 metres TVD MSL. The Hugin Formation was deposited in a paralic environment with proximal to distal mouth bars, lower shore face, middle shore face and upper shore face to barrier sands and coals. The reservoir is capped by Heather shales. Base reservoir is a coal layer on top of the Sleipner Formation.

The drive mechanism will be gas injection. According to the PDO the Gina Krog Field development will comprise of eight horizontal oil producers, three gas injectors and three gas producers.

Development
Gina Krog is developed with a fixed platform located on the Central 1 segment. Gas will be exported through a tie-back to Sleipner East, while oil is loaded offshore to shuttle tankers.

The drive mechanism is gas injection. The field is planned developed with eight horizontal oil producers, three gas injectors and three gas producers as defined in the PDO. The plan allows for additional wells, and the production wells are drilled using geosteering. Some changes to the original plan are expected when new well information becomes available.

Injection gas is imported from Gassled. In addition, it will also be possible to inject gas from the nearby Eirin discovery if that discovery is developed. Gas injection at the crest of the field will add to the gas cap expansion and displace condensate rich gas towards the producers. Injectors will be converted to producers when the injection phase is completed. Three wells are included to produce gas from areas without an oil rim.

Status

The PDO was approved by the authorities in May 2013. Pre-drilling of development wells was performed in 2015 and 2016. The drilling rig was used as living quarters during the hook-up and commissioning period. The current drilling plan is adjusted according to the pre-drilling experience. The facilities were installed and commissioned only slightly behind plan. After installation and commission drilling operations commenced in September 2017. One pre-drilled gas producer and three pre-drilled oil producers started production on 30 June 2017. Gas injection commenced at the end of 2017, about two months delayed.

The initial oil production has been below expectations, especially from well B-17 in the East 1 segment experiencing slugging. However, gas productivity in B-7 has been much higher than expected. It is somewhat surprising that wells B-17 and B-6 shows lower production than expected, even though the permeability along the wells was as good or higher than expected.

The recoverable volumes are classified as "Reserves; On Production" (SPE's classification system).

The field is unitized and Aker BP holds an interest of 3.3% in the unit. The operator Statoil Petroleum AS holds a 58.7% interest, Total E&P Norge 15%, KUFPEC Norway AS 15% and PGNiG Upstream International AS the remaining 8%.

3.2 Development Projects

3.2.1 Johan Sverdrup (PL265, PL501, PL502, PL501B)

Johan Sverdrup is a major oil field extending over four licences (PL265, PL501, PL501B and PL502). The joint plan for development and operation (PDO) was approved in 2015. The field is located in a half-graben on the Utsira High in the North Sea, approximately 140 kilometres west of Stavanger in blocks 16/2, 16/3, 16/5 and 16/6; see Fig. 3.11. The water depth in the area is 110 - 120 metres and the reservoir depth is about 1,900 metres TVD MSL.

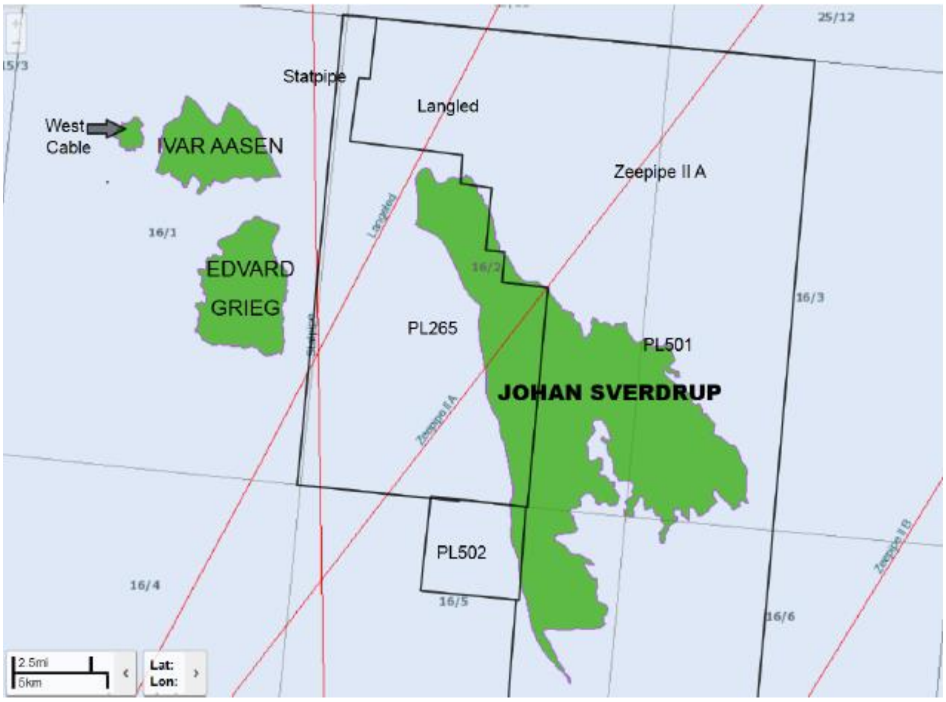

Fig. 3.11 Johan Sverdrup location map

Discovery
The discovery well 16/2-6 was drilled in 2010 on the Avaldsnes prospect on the Utsira High. The well proved oil in Upper Jurassic to Upper Triassic sandstones in the Karmsund Graben. More than 35 wells have been drilled since then to appraise the discovery. In addition 8 production wells and 9 water injection wells have been pre-drilled during 2016 and 2017.

Reservoir
The reservoir consists of late Jurassic sediments in the Draupne sandstone and late Triassic to early Jurassic to sandstones in the underlying Statfjord Formation/Vestland group. The reservoir is characterized by excellent reservoir properties. The apex of the field is estimated at approximately 1,800 metres TVD MSL and the free water levels (FWL) encountered are in the range of 1,922 - 1,934 metres TVD MSL. Top reservoir is flat whereas the base is irregular. Gross reservoir thickness varies from up to ~90 metres in the central/western parts of the field to less than 10 metres in the fringes, with several parts of the field having thin reservoir at the brink of seismic resolution.

The reservoir fluid is highly under-saturated light oil with a low GOR of approximately 40 Sm3/Sm3 and with a viscosity of approximately 2 cP.

The field will in general be developed with producers located in the central/western thicker parts of the field with water injection wells located down dip in the water zone in the eastern and southern parts of the field.

Development
The core of the Phase 1 development plan will be a field centre with four platforms; processing platform, drilling platform, riser and export platform and living quarters and utilities platform; Fig. 3.11. The platforms will be installed on steel jackets linked by bridges. Phase 1 also includes 18 oil production and 16 water injection wells, 3 subsea water injection templates, oil and gas export pipelines and 100 MW power from shore. The oil will be transported to the Mongstad terminal and

the small amounts of associated gas will be transported via the Statpipe system to Kårstø for processing and onward transportation. The Phase 1 production is expected to be approximately 440 mbopd. Planned production start for Phase 1 is December 2019.

The Phase 2 (the full field development) will develop the reserves in the fringe areas of the field as well as enable acceleration of the production from the Phase 1 area. The PDO for the future phases is planned for the second half of 2018 and production start is planned in 2022. Fully developed, approximately 62 oil production and water injection wells will be drilled on Johan Sverdrup and the oil plateau production is expected to be approximately 660 mbopd.

DG2 for phase 2 was passed in March 2017. The development includes an additional processing platform (P2) located next to the riser platform at the field centre, Fig. 3.12. The Phase 2 wells will be a mixture of satellite wells and additional wells drilled from the central drilling platform DP. The fringe areas will be developed with five subsea templates tied back to the riser platform (RP). The power from shore capacity will be expanded from 100 to 300 MW, which also enables serving adjacent fields on the Utsira High with power (Edvard Grieg, Ivar Aasen and Gina Krog).

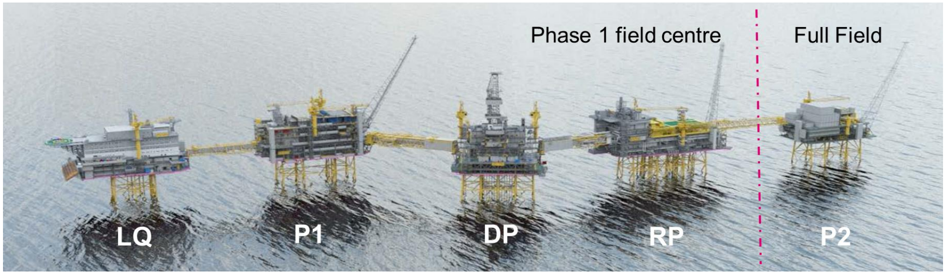

Fig. 3.12 Johan Sverdrup field center

The export solution for oil and gas will be transportation to shore via dedicated pipelines. The oil will be transported to the Mongstad terminal and the gas will be transported via the Statpipe system to Kårstø for processing and onward transportation.

Status

A total of 16 new wells were drilled in the period October 2016 to October 2017. Of these 2 were production wells, 9 were water injection wells and 5 were pilot or appraisal wells. Overall the wells came in according to prognoses. Of the five pilot/appraisal wells three found thicker, and one found thinner sands than prognosed in Draupne. For the water injection wells three found shallower and thicker and one found shallower and thinner sands in Draupne. The oil production wells were horizontal, hence gave limited new information regarding reservoir thickness.

The preliminary results of the updated modelling by the operator (Preliminary DG3 model) shows an increase in both in-place and recoverable resources compared to the Phase 1 DG3 model and Phase 2 DG2 model. The Reference Case from "Phase 2 preliminary DG3 model" is very close to the Aker BP reference case from 2015.

Note also that Aker BP has included reserves assuming a full field development of the field in the reserve base (both Phase 1 and Phase 2).

Several IOR/EOR techniques are identified which may increase the reserves on Johan Sverdrup. The most promising are WAG (water alternating with gas injection) and infill drilling with a common potential in the range of some 25 mmboe net to Aker BP. Please note that a DG3 for WAG injection with a potential net Aker BP reserve addition of approximately 8 mmboe will most likely be passed together with the Phase 2 DG in second half of 2018.

Aker BP has 11.5733% interest in Johan Sverdrup. The remaining shares are held by Statoil Petroleum AS (40.0267%), Lundin Norway AS (22.6000%), Petoro AS (17.3600 %) and Maersk Oil Norway AS (8.4400%). The Joint Unit Agreement opens for one potential redetermination of equity interests, in 2025.

3.2.2 Oda (PL405)

The Oda Field is located 14 kilometres west of the Ula Field in block 8/10 in PL405 in the Central Graben in the Norwegian North Sea. Fig. 3.13 shows the location of the asset. The water depth is about 66 metres in the area, and the crest of the structure is estimated to be at 2,300 metres TVD MSL.

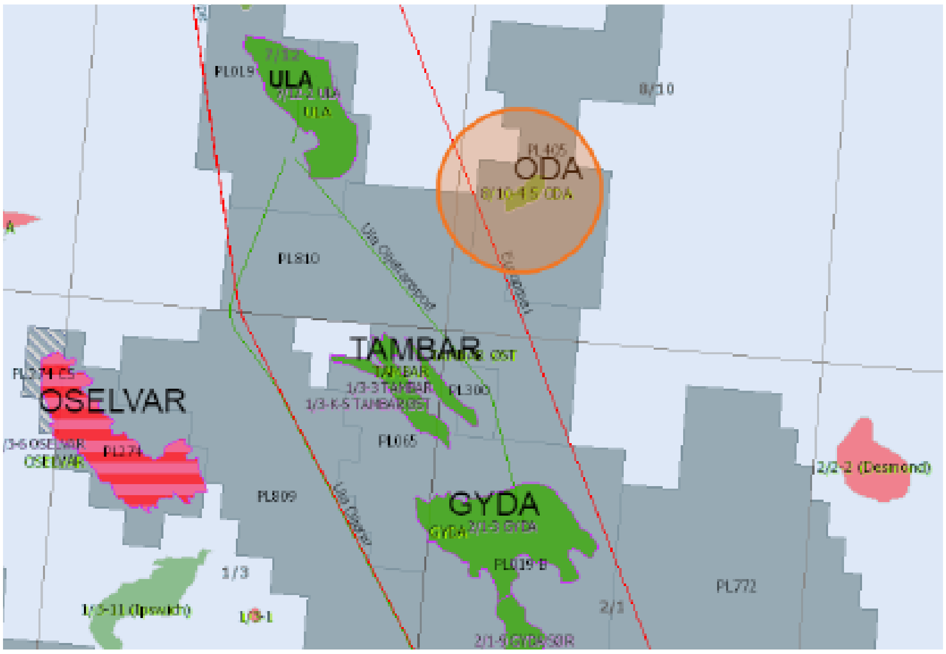

Fig. 3.13 Oda location map

Discovery
The discovery well 8/10-4 S was drilled in 2011 in the north-eastern part of the salt-induced structure. The well proved an oil-down-to situation in the Ula Formation. A water gradient in a downflank sidetrack suggests a FWL at 2,985 metres TVD MSL. East and south-west segments were drilled dry in 2014.

Reservoir
The reservoir consists of the Upper Jurassic Ula Formation; a sandstone reservoir with high quality properties. The Oda structure forms the flank of a steep dipping salt diapir. The oil column is about 685 metres of light oil.

The drainage strategy calls for pressure maintenance via seawater injection. Two oil producers and one water injector is planned.

Development
The development concept is a subsea tie-in to the Ula Platform and re-usage of the Oselvar subsea isolation valve (SSIV) inlet facility and separator at the Ula Platform. Modifications at Ula include installation of a new water injection system, riser caisson for water injection, and umbilical and new equipment for incremental water handling.

Status
The PDO was approved by the authorities in May 2017. Production start is expected in August 2019, with a tie-in to the Ula Field. The Ula Field is operated by Aker BP.

The recoverable volumes of Oda are classified as "Reserves; Approved for Development" (SPE's classification system).

Aker BP holds a 15% interest in the Unit. The remaining shares are held by Spirit Energy Norge AS (40%, Operator), Suncor Energy Norge AS (30%) and Faroe Petroleum Norge AS (15%).

3.2.3 Ærfugl (Skarv Unit, PL212E)

Ærfugl (former Snadd) is a gas condensate field located about 35 kilometres south-west of the Norne Field in the northern part of the Norwegian Sea in the Skarv Unit in blocks in 6507/2, 6507/3, 6507/5 and 6507/6, see Fig. 3.9. The water depth in the area is 350 - 450 metres and the reservoir depth is about 2,800 metres TVD MSL. The water depth in the area is 350 - 450 metres and the reservoir depth is about 2,800 metres TVD MSL. The field was tested through one producer tied into the Skarv facilities for five years prior to the field development decision. The PDO was submitted in December 2017.

Discovery
The Ærfugl Field was discovered in 2000 with well 6507/5-3. It was appraised in 2010/2011 by wells 6507/5-6 S, 6507/5 A-1 H, 6507/5 B-5, and 6507/3-9 S for Snadd Outer.

Reservoir
The reservoir is almost 60 kilometres long and only 2 to 3 kilometres wide. The thickness varies from 5 to 60 metres in the hydrocarbon bearing area. The reservoir in Ærfugl is the Cretaceous Lysing Sandstone Formation with good reservoir properties (average porosity 21.4 percent, permeability 234 mD and net/gross of 0.85).

Development
The Ærfugl Field will be produced through the existing facilities on Skarv. The depletion plan includes 6 new highly deviated subsea wells plus the existing test well A-1 H tied into the Skarv FPSO with heated flowlines. Phase I includes 3 wells on Ærfugl South with production start Q4 2020. Phase II includes 3 wells on Ærfugl North and Snadd Outer with tie-in Q4 2023.

Status
The A-1 H test producer in Ærfugl started gas production February 2013, one month after the start-up of the Skarv Field. The well has received four approvals from the authorities for test production and pressure build-up analysis, each 0.75 - 1.0 GSm3. Approved gas quantity of 0.75 GSm3 for 2017 was produced by 21 August 2017, and the well was shut in pending PDO delivery. On 5th December a fifth test production period was approved and the well put back on stream pending PDO approval. It is assumed that well A-1 H will be put on permanent production once the PDO is approved. The PDO was submitted in December 2017. Producing this well has provided excellent data which has helped to significantly de-risk the Ærfugl development. The well has per now produced approximately 6 percent of the P50 GIIP of Ærfugl Main and Snadd Outer.

The recoverable volumes of Ærfugl are classified as "Reserves / Justified for development" (SPE's classification system).

The southern part of the Ærfugl Field is located in the Skarv Unit. Aker BP holds a 23.8% share in the the Unit. The northern part of the field (Snadd Outer) is located in license PL212E in which Aker BP holds a share of 30%.

3.2.4 Skogul (PL460)

The Skogul oil field is located approximately 40 kilometres north of Alvheim in block 25/1 under PL460 in the Central Viking Graben in the Norwegian North Sea and consists of Eocene Balder and Frigg Formation deep marine deposited sandstones. The water depth is about 107 metres in the area, and the crest of the structure is estimated to be at 2,097 metres TVD MSL. The PDO was submitted in December 2017.

Discovery
The discovery well 25/1-11 R and the sidetrack well 25/1-11A were drilled in 2010 and proved a thin gas cap overlying a 20 metres oil column within excellent reservoir quality Upper Balder-Frigg Formation sandstones. Vertical well 25/1-11R was drilled on a structural high with a strong amplitude anomaly, encountering a 13 metres oil column and an oil water contact (OWC) was proven at 2,126 metres TVDSS. A deviated (29°) sidetrack well, 25/1-11A, was subsequently drilled higher on the structure, but in an area with a dimmer amplitude anomaly. This well encountered a small gas cap with a gas oil contact (GOC) at 2,106 metres TVDSS and a 12 metres oil column.

Reservoir
The reservoir consists of the Lower Eocene Upper Balder-Frigg Formation sandstones; sandstone reservoirs with good quality properties. Upper Balder and Frigg Formation sandstones were derived from the East Shetland Platform to the west and deposited from deep marine turbidity currents as part of the Frigg submarine fan. In well 25/1-11R the Skogul reservoir interval of 21.7 metres TVD MSL contains 20.1 metres MD of reservoir sand with a porosity of 31 percent, giving a net-to-gross ratio of 92.4 percent. In Well 25/1-11 A the Skogul reservoir interval of 14.1 metres MD contains 12.6 metres MD of reservoir sand with a porosity of 32 percent, giving a net-to-gross ratio of 89.2 percent.

Development
Skogul is planned to be developed as a tie-in to Alvheim FPSO via the Vilje manifold and pipeline. The concept is one bilateral producer, requiring a new two-slot manifold. A pilot will be drilled in order to ensure optimal depth of the long horizontal branches. Skogul is assumed to lie within a region with an extensive aquifer system, hence the drive mechanism will be by depletion and natural aquifer support. The pressure support ability from this aquifer is one of the main uncertainties, and poor aquifer support will be mitigated by assisted pressure support by constructing a conduit for water flow from the extensive Heimdal aquifer, along the northern well and into the reservoir. The subsea system will be tied back to Alvheim FPSO via the Vilje template. Production from Skogul will be measured by a dedicated subsea multiphase meter. The commingled production from Vilje and Skogul will be measured through a dedicated topside multiphase meter on Alvheim. Screens, ICDs and swell packers will be used in order to avoid sand production and minimize water production.

Status
The PDO was submitted Q4 2017 and first oil is expected Q1 2020.

Aker BP is the operator and holds a 65% interest in the Skogul Field. The remaining 35% interest is held by PGNiG.

4 Contingent Resources

Aker BP has contingent resources in a wide range of assets. The total net contingent resources estimates included in the resource classes "Development Pending" and "Development not clarified or on hold" (see Fig. 1.1) ranges from 500 to 1,103 mmboe. Approximately 53 percent of this is associated with further development of the fields containing reserves described in 3 Description of Reserves.

Further development of the Valhall and Hod fields with estimated sanctions in the period 2020 to 2022 is by far the most important contributor to future reserves growth in Aker BP and several opportunities are identified. The two most important projects being the Lower Hod Formation development on Valhall and the Hod Redevelopment project. The Valhall total potential represents approximately 48 percent of the company's total contingent resources estimate.

The following is a short description of the most important discoveries within the company’s core areas containing contingent resources. Only contingent resources in the resource classes "Development Pending" and "Development not clarified or on hold" are included (see Fig. 1.1), and resources in NPD classes 6 and 7 (see Fig. 1.2) are excluded.

North of Alvheim Area and the Krafla/Askja Area (NOAKA)
The NOAKA area consists of the Frigg Gamma Delta, Langfjellet, Frøy, Fulla and Askja-Krafla discoveries. In addition, the Rind and Frigg discoveries are considered to be part of the area development. The area development is a shared initiative between the partners in the licenses.

With limited infrastructure available in the area, the goal currently is to develop an economically robust area solution which can tie-in neighbouring licenses and open up the area for new exploration upsides. The area development solution is likely to include subsea structures and unmanned/normally unmanned installations on the individual reservoirs based on their size and complexity. The project is expected to be further matured towards a planned concept selection, decision in the first quarter of 2018. A concept selection decision is planned in 2018.

Askja/Krafla Area (PL272, PL035, PL035C)
Krafla and Askja are considered to be developed as part of the NOAKA area. The Krafla discoveries (wells 30/11-8S and 30/11-8A) are located in the northern part of the North Sea, between the Oseberg and Frigg fields. The water depth is 108 metres. Krafla is located adjacent to the Askja discovery made in 2013. In Askja, Aker BP participated in two discoveries in the Askja West and Askja East prospects in 2013. In Askja West, a 90 metres gas column was encountered, while a 40 metres net oil column was found in Askja East. The Krafla project is currently in the concept selection phase.

Since discovering Krafla Main and Krafla West, several wells have been drilled in the license area. These wells are set out in the table below:

- 30/11-8S, **Askja East** prospect in 2013 - oil discovery
- 30/11-9ST2, **Askja West** prospect in 2013/2014 - gas discovery
- 30/11-10S, **Krafla North** prospect in 2014 - oil discovery
- 30/11-10A, **Krafla Main** appraisal 2014/2015
- 30/11-11S, **Madame Felle** prospect in 2016 - oil discovery
- 30/11-11A, Viti prospect in 2016 - dry
- 30/11-12S, **Askja South East** prospect in 2016 - oil discovery

- 30/11-12A Askja SE downflank in 2016 - oil discovery
- 30/11-13 **Beerenberg** prospect in 2016 - gas discovery
- 30/11-14 **Slemmestad** prospect in 2016 - gas discovery
- 30/11-14B **Haraldsplass** prospect in 2016 gas discovery

Fig. 4.1 shows a location map of the Krafla/Askja area.

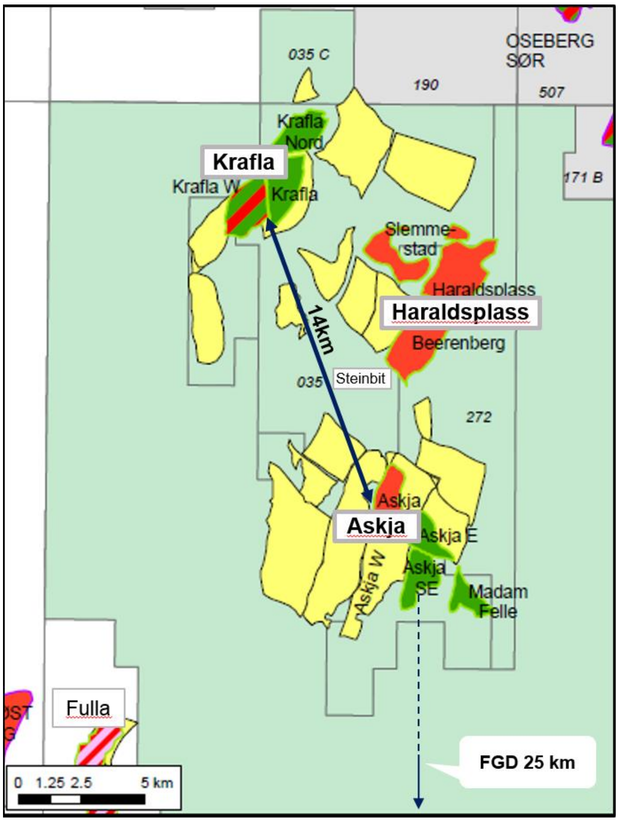

Fig. 4.1 Krafla/Askja area location map

The reservoir section in all the discoveries are the Middle Jurassic Tarbert and Ness Formations with fair to good reservoir quality. Reservoir depths vary from approximately 2,900 mTVD to approximately 3,800 mTVD.

All the discoveries has been estimated using state of the art reservoir evaluation tools utilizing all available data. The combined net resource potential for Aker BP for the area ranges from 65 to 166 mmboe.

The Krafla project is in the concept selection phase, and the current schedule implies a DG2 in 2017.

Aker BP has 50% interest in licenses PL035/PL035C and PL272. Statoil Petroleum AS is operator for the licenses and holds the remaining 50%.

The **Frøy Field (PL364)** is part of the NOAKA area. It was in production from 1995 to 2001 with Elf as the operator. Elf shut down the field in 2001 due to several reasons, including technical challenges, recovery rates falling below expectations and low oil prices. The licensees have worked on getting the field redeveloped. In 2008, a PDO was submitted, but was postponed due to the financial crisis. Through 2010, the Frøy group matured alternative concepts to establish a more robust concept featuring a leased field center (FPSO/JUDPSO) combined with a WHP. The goal was to deliver an updated PDO. During spring 2011, the work on preparing an updated Frøy PDO, however, was put aside. A re-development of Frøy is being evaluated in the context of the NOAKA area's development.

Aker BP is the operator for all the discoveries in the area and holds a 90.26% interest in Frøy.

Frigg Gamma Delta (PL442) is part of the NOAKA area. It is a discovery in the North Sea, located about 20 kilometres east of the Frigg. Water depth in the area is approximately 120 metres. The discovery was proven by well 25/2-10S, located in the Frigg Gamma structure, in 1986. The reservoir contains oil and gas in sandstone located within the Frigg formation, which is dated to the Eocene age. The reservoir is located at approximately 1,900 metres depth. Additional resources are located in the East Frigg Delta (PL442), and were proved by well 25/2-17 in 2009. Frigg Gamma Delta is currently being evaluated in the context of the overall area development.

Aker BP holds 90.26% interest in the Frigg Gamma Delta discovery.

Langfjellet (PL442, 25/2-18) was discovered in 2016 and contains oil in the Middle Jurassic Hugin- and Sleipner Formations. Several sidetracks were drilled and two successful formation tests (DST) were conducted in well 25/2-18A. The maximum production rate was 3,800 mbopd through a 40/64 inch choke in the lower oil zone. The wells were drilled four kilometres south of Frigg Gamma Delta and eight kilometres north of Frøy.

Aker BP holds 90.26% interest in the Langfjellet discovery.

Fulla (PL873, 30/4-7) is a gas/condensate discovery made by well 30/11-7 in 2009. The discovery is located about ten kilometres northeast of the Frigg field. The water depth in the area is approximately 110 metres. The reservoir contains gas and condensate in the middle Jurassic Ness formation at a depth of approximately 4,000 metres.

Aker BP is operator and holds 40% interest in the Fulla discovery.

Rind (PL026, 25/5-5) is an oil/gas discovery made in 1976. The discovery contains oil and gas in the middle Jurassic Brent group and in the Statfjord Formation. Total E&P Norge AS is operator. Aker BP holds a 30% interest in the discovery.

Fig. 4.2 shows a location map of the North of Alvheim Area (NOA).

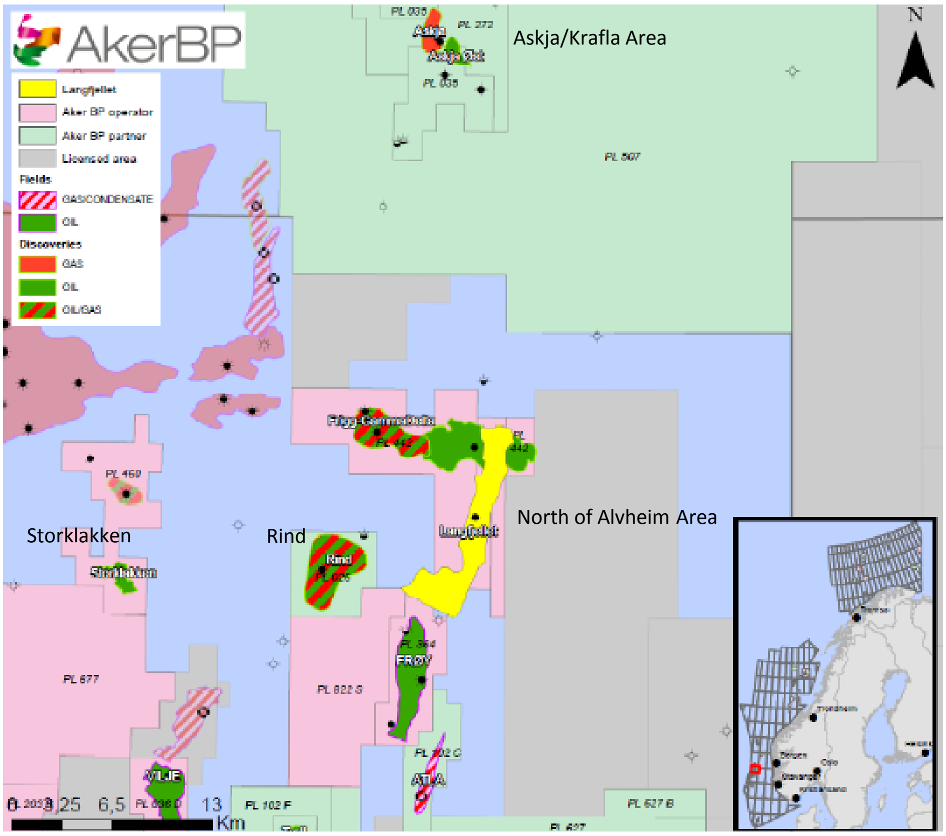

Fig. 4.2 North of Alvheim location map
Askja /Krafla area located north of NoA and the Rind and Storklakken discoveries to the west.

The combined net resource potential for Aker BP for the North of Alvheim Area ranges from 99 to 213 mmboe. The NOA area together with the Askja Krafla Area represent approximately 36 percent of Aker BP's total net estimated resources.

<u>Alvheim Area</u>

The **Gekko (PL203)** gas discovery is located approximately 10 kilometres south-east of Alvheim and was discovered in 1974. The reservoir sandstones are within the Paleocene Heimdal Formation. Current plan involves drilling an appraisal well in 2018 after which the development concept for a potential oil and gas development can be determined. Possible production start is 2021. Aker BP holds a 65% share in the discovery.

The **Caterpillar (PL340 BS)** oil discovery is located some 35 kilometres south of Alvheim and approximately 6 kilometres south east of Bøyla and was discovered in March 2011. The reservoir consist of the Hermod Formation of late Paleocene age. Current volumes and profiles are based on an updated uncertainty assessment in August 2015. Base case development scenario assumes a single producer subsea tieback development to Alvheim FPSO with gas lift. Start-up is assumed in 2022.
Aker BP holds a 65% share in the discovery.

The combined net resource potential for Aker BP for the Alvheim area ranges from 21 to 39 mmboe which includes a minor contribution for a possible sidetrack of one of the Volund producers.

Valhall Area

Several projects which may increase the reserves from the Valhall and Hod fields significantly are identified. The following is a list of projects included in the resource classes "Development Pending" and "Development not Clarified or on Hold", Fig. 1.1.

- Hod Extended Production (new)
- Hod Re-development (new - two projects reported in 2016 combined to one project)
- Hod Re-development Expansion
- Hod Upper Diatomite (Miocene)
- Valhall Additional Crest Infill Drilling
- Valhall Additional Flank Infill Drilling (new)
- Valhall Extended Production (new)
- Valhall Flank South Infill Drilling
- Valhall Flank South West Infill Drilling (new)
- Valhall Flank West Waterflood (new)
- Valhall Lower Hod Formation Development
- Valhall Upper Diatomite (Miocene) (new)

Some of these projects are expected to be sanctioned within 2018 and 2019 while other will need further maturing prior to sanction.

The combined net resource potential for Aker BP for the Valhall Area ranges from 270 to 550 mmboe. This is a substantial increase from last years reporting and is partly due to increased equity on the field and partly due to new projects included. Note that the two projects Valhall Flank West Development and Valhall Flank North Water Injector has been matured from contingent resources to Reserves during 2017.

Skarv Area

The **Gråsel** discovery may contribute with minor amount of oil and gas. The Gråsel discovery was made by the Skarv discovery well 6507/5-1 in 1998. The reservoir units consists of the Late Cretaceous Lange Formation. The discovery has been penetrated by five Skarv wells and current development plan includes reuse of one Skarv producer and one Skarv injector.

Garantiana (PL554)

The Garantiana discovery is an elongated structure with a gross ~100 metres thick Early Jurassic / Cook formation / medium quality reservoir (200-400 mD) located at a depth of approximately 3,700 metres TVD MSL in the northern north sea. The reservoir is high pressure (630 bar) with somewhat challenging fluid characteristics (high content of CO_2, H_2S, high Pour point pressure and risk of asfalthene precipitation).

Garantiana has been appraised by 34/6-2S and 2A in 2012 (central area) and by 24/6-3S in 2014 (south area). The southern area has proven good reservoir properties through drill stem tests, the middle area has poorer characteristics and the middle area has poorer characteristics and the northern area is not appraised.

Updated volumes estimates indicate a net resource potential ranging from 13 to 28 mmboe to Aker BP. The discovery will most likely be developed as a subsea tie-back to existing infra structure. Thus, a development will be dependent on available process capacity in the area. Current plans indicates production start in 2021.

Total E&P is operator and Aker BP holds a 30% interest in PL554.

Gohta (PL492)
The Gohta discovery, located on the southern part of the Loppa High in the south west Barents Sea was discovered in 2013 by well 7120/1-3. The well proved oil with an overlaying gas cap in Permian porous karstified carbonates of the Tempelfjorden Group. An appraisal well was drilled in 2014, 7120/1-4. Both wells were tested. Well 7120/1-3 tested the oil zone. Well 7120/1-4 produced gas from the gas zone but failed to produce from the oil zone. It is uncertain if this is related to reservoir performance or to a poor cement job before the DST. A third appraisal well is planned in 2017 targeting more reservoir units in the northern part of the structure.

A possible development will most likely be a common development with a nearby discoveries. Current net recourse potential to Aker BP ranges from 14 to 51 mmboe.

Lundin Norway AS is operator for PL492 and Aker BP holds a 40% interest in the licence.

Filicudi (PL533)
In 2017, well 7219/12-1 made the Filicudi discovery in the Barents Sea.

Lundin Norway AS is operator for the license and Aker BP holds a 35% interest in PL533. Current volume estimates indicate a resource potential ranging from 7 to 10 mmboe net to Aker BP.

Other
Other resources classified in the resource classes "Development Pending" and "Development not clarified or on hold" includes the Total operated Trell (PL102F, 2014) discovery, a very likely WAG project on Johan Sverdrup, infill wells on Gina Krog and Ivar Aasen and several IOR projects on the Ula and Tambar fields.

The combined net resource potential for Aker BP for these projects ranges from 9 to 43 mmboe.

5 Management's Discussion and Analysis

The assessment of reserves and resources is carried out by experienced professionals in Aker BP based on input from operators, partners, and in-house evaluations. The responsibility to carry out the evaluation lies with the business projects. The reserves and resource accounting is coordinated and quality controlled by a small group of professionals, headed by a reservoir engineer with more than 20 years of experience in such assessments.

Additionally, all volumes (except for the minor Enoch and Atla Fields) have been certified by an independent third party consultancy (AGR Petroleum Services AS). These are the producing fields Alvheim (including Boa), Vilje, Volund, Bøyla, Ivar Aasen, Valhall, Hod, Ula, Tambar, Tambar East and Gina Krog and the fields under development; Hanz, Johan Sverdrup, Oda and Skogul.

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields on the basis of expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves is set at zero cash flow or when facility lease expires. The company has used a long term inflation assumption of 2.5 percent, a long term exchange rate of 7.5 NOK/USD, and a long term oil price of 66 USD/bbl (real 2017 terms).

The calculations of recoverable volumes are, however, associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 estimate reflects our high confidence volumes. The methods used for subsurface mapping do not fully clarify all essential parameters for either the actual hydrocarbons in place or the producibility of the hydrocarbons. Therefore there is a remaining risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the reserves. Low oil prices may force the licensees to close down producing fields early and lead to lower production. Higher oil prices may extend the life time of the fields beyond what is currently assumed.

Karl Johnny Hersvik
CEO