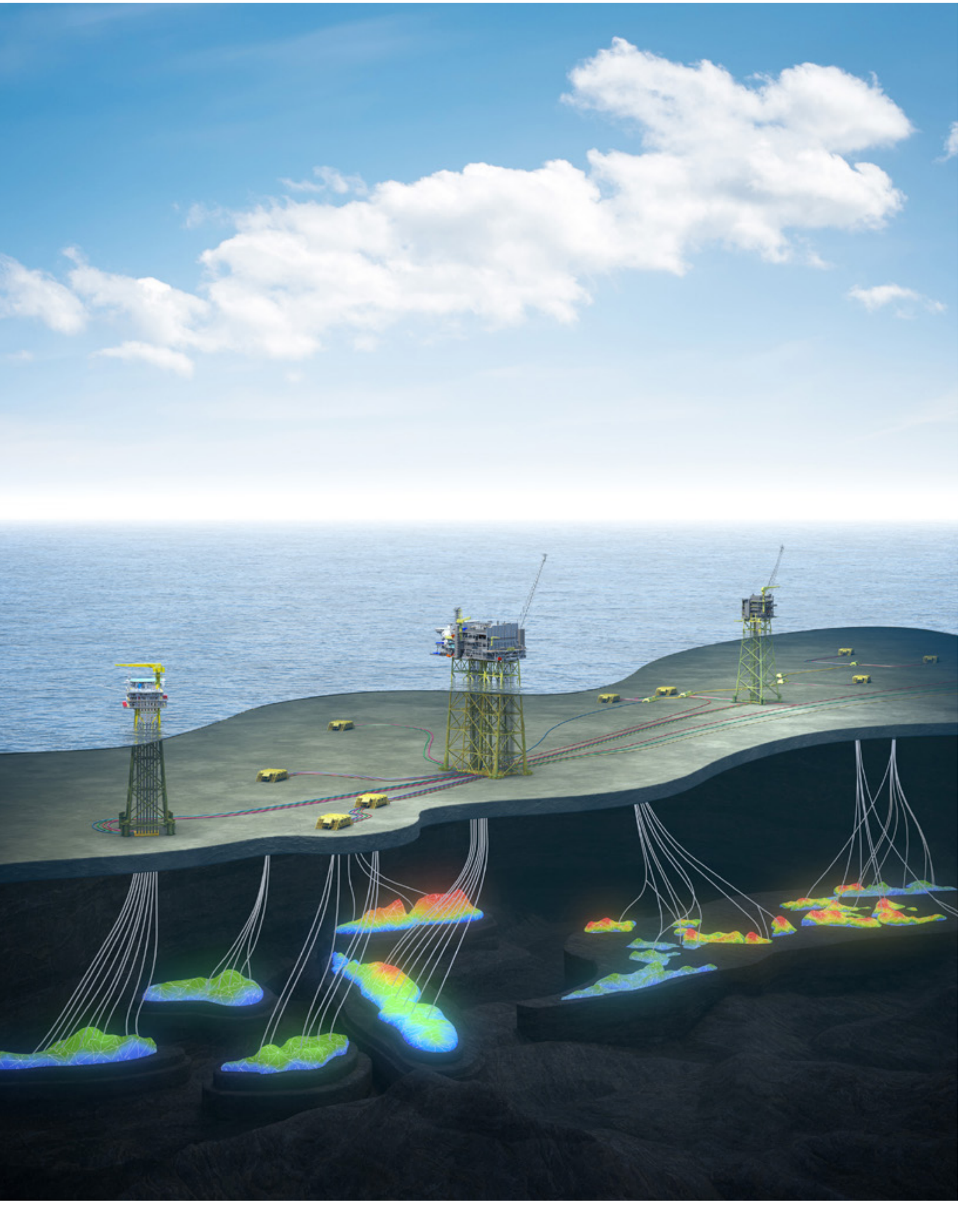
Annual Statement of Reserves

2024



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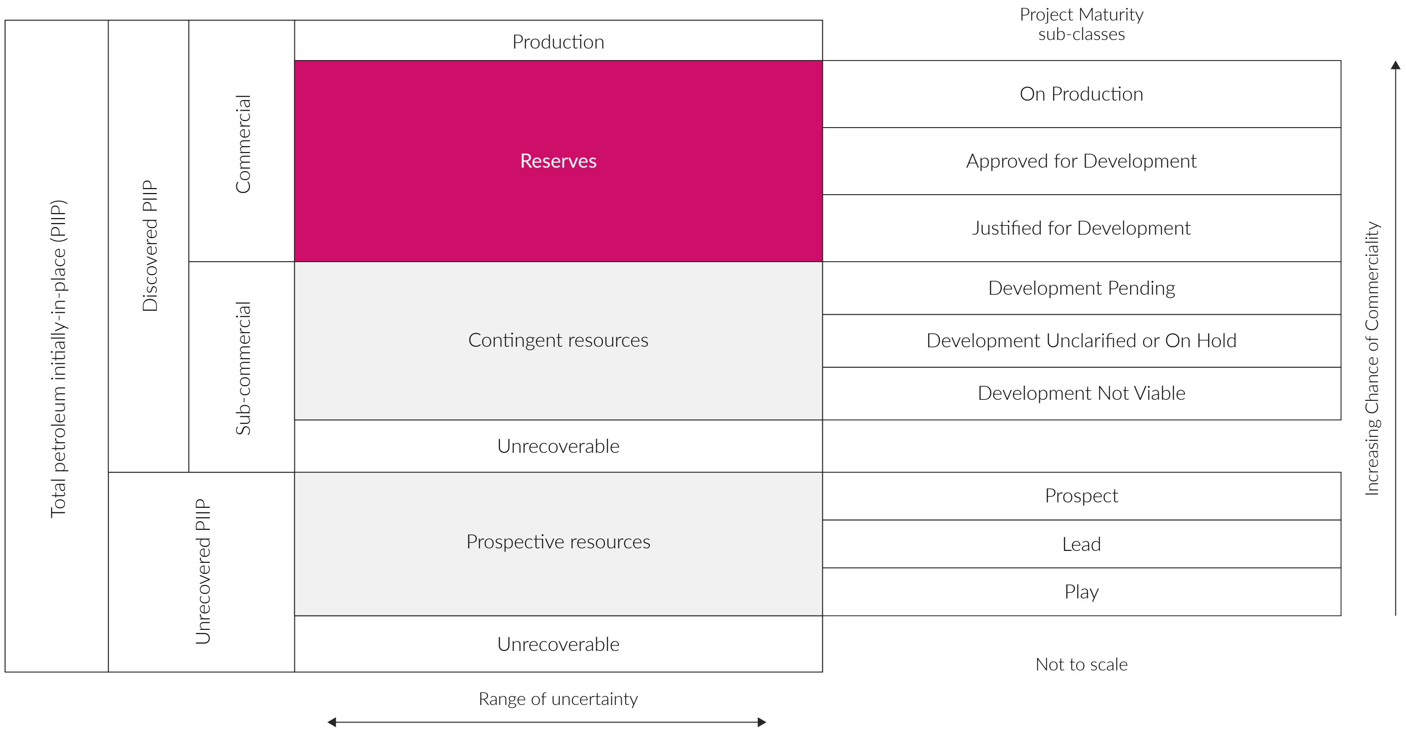
1. Classification of reserves and contingent resources

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 Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in Figure 1.1.

Figure 1.1: **SPE reserves and resources classification system**



2. 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 simulation models in combination with decline analysis have been used to generate profiles.

Note that an independent third party, AGR Petroleum Services, has certified all reserves except for the minor asset Enoch, due to the small size of this field, representing approximately 0.0004 percent of total 2P reserves.

Aker BP ASA has a working interest in 52 fields/projects containing reserves, see Table 2.1. Of these fields/projects, 25 are in the sub-class "On production"/developed, 26 are in the sub-class "Approved for development"/undeveloped and 1 is in the sub-class "Justified for development"/undeveloped. Note that several fields have reserves in more than one reserve sub-class.

Figure 2.1: **Aker BP fields and projects containing reserves**

Project	Interest	Operator	Resource class	Comments
		Developed Reserves		
Alvheim Base	80.0 %	Aker BP	On production	Gas blow down as "Approved"
Boa Base	70.9 %	Aker BP	On production	
Bøyla Base	80.0 %	Aker BP	On production	
Skogul Base	65.0 %	Aker BP	On production	
Tyrving	61.3 %	Aker BP	On production	
Vilje Base	46.9 %	Aker BP	On production	
Volund Base	100.0 %	Aker BP	On production	
Edvard Grieg Base	65.0 %	Aker BP	On production	
Solveig Base	65.0 %	Aker BP	On production	
Troldhaugen EWT	80.0 %	Aker BP	On production	2025-production, only
Hanz Base	35.0 %	Aker BP	On production	
Ivar Aasen Base	36.2 %	Aker BP	On production	
Skarv Base	23.8 %	Aker BP	On production	
Skarv Gråsel	23.8 %	Aker BP	On production	
Skarv Idun Tunge	23.8 %	Aker BP	On production	
PL212E Ærfugl Nord Base	30.0 %	Aker BP	On production	
Skarv Ærfugl	23.8 %	Aker BP	On production	
Skarv Ærfugl Infill A02	23.8 %	Aker BP	On production	
Tambar Base	55.0 %	Aker BP	On production	
Ula Base	80.0 %	Aker BP	On production	
Hod Base	90.0 %	Aker BP	On production	
Valhall Base	90.0 %	Aker BP	On production	
Johan Sverdrup Base	31.6 %	Equinor Energy AS	On production	
Oda Base	15.0 %	Sval Energi AS	On production	Aker BP from 1 February 2025
Enoch	2.0 %	Repsol Sinopec		

Project	Interest	Operator	Resource class	Comments
Undeveloped Reserves				
Frosk Attic	80.0 %	Aker BP	Approved for development	
Gekko Blowdown	80.0 %	Aker BP	Approved for development	
Kameleon Gas Cap Blow Down	80.0 %	Aker BP	Approved for development	
Edvard Grieg IOR 2025 A-09	65.0 %	Aker BP	Approved for development	
Edvard Grieg IOR 2025 A-19B	65.0 %	Aker BP	Approved for development	
Solveig Ph2	65.0 %	Aker BP	Approved for development	
Symra	50.0 %	Aker BP	Approved for development	
PL127C Alve Nord Development	68.1 %	Aker BP	Approved for development	
PL159D Idun Nord Development	23.8 %	Aker BP	Approved for development	
PL942 Ørn Development	30.0 %	Aker BP	Approved for development	
Skarv Tilje Infill A05	23.8 %	Aker BP	Approved for development	
Tambar East K5 Sidetrack	46.2 %	Aker BP	Approved for development	
Tambar K-3 Recompletion	55.0 %	Aker BP	Approved for development	
Ula WAG from K-5B	80.0 %	Aker BP	Approved for development	
Fenris	77.8 %	Aker BP	Approved for development	
Valhall PWP	90.0 %	Aker BP	Approved for development	
Frigg Gamma Delta Development	87.7 %	Aker BP	Approved for development	
Frøy Development	87.7 %	Aker BP	Approved for development	
Fulla Development	47.7 %	Aker BP	Approved for development	
Krafla/Askja Development	50.0 %	Aker BP	Approved for development	
Langfjellet Development	87.7 %	Aker BP	Approved for development	
Lille Frigg Development	47.7 %	Aker BP	Approved for development	
Rind Development	87.7 %	Aker BP	Approved for development	
Johan Sverdrup RMLT 2025	31.6 %	Equinor Energy AS	Approved for development	
Johan Sverdrup WAG	31.6 %	Equinor Energy AS	Approved for development	
Verdande Development	7.0 %	Equinor Energy AS	Approved for development	
Valhall Flank West V-1 and V-10 Infills	90.0 %	Aker BP	Justified for development	

Aker BP's total net proven reserves (P90/1P) as of 31 December 2024 are estimated at 1,071 million barrels of oil equivalent. Total net proven plus probable reserves (P50/2P) are estimated at 1,568 million barrels of oil equivalent. The split between liquid and gas and between the different subcategories for all fields/projects is provided in Table 2.2.

Figure 2.2: **Aker BP 1P and 2P reserves as of 31 December 2024 per projects and reserve class**

Reserves pr 31.12.2024	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe
	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
On production											
Alvheim Base	80.0 %	39	0	16	56	45	47	0	20	67	53
Boa Base	70.9 %	8	0	1	9	6	9	0	2	11	8
Bøyla Base	80.0 %	5	0	1	6	5	8	0	1	9	7
Skogul Base	65.0 %	1	0	0	1	1	4	0	0	4	3
Tyrving	61.3 %	21	0	0	21	13	24	0	1	24	15
Vilje Base	46.9 %	3	0	0	3	1	7	0	0	7	3
Volund Base	100.0 %	3	0	0	4	4	5	0	1	6	6
Edvard Grieg Base	65.0 %	59	4	6	69	45	71	4	8	83	54
Solveig Base	65.0 %	27	4	6	37	24	37	5	7	49	32
Troldhaugen EWT	80.0 %	0	0	0	0	0	0	0	0	0	0
Hanz Base	35.0 %	2	0	1	3	1	4	0	1	6	2
Ivar Aasen Base	36.2 %	26	2	6	34	12	32	3	9	44	16
Skarv Base	23.8 %	2	6	30	37	9	2	7	36	45	11
Skarv Gråsel	23.8 %	1	1	3	4	1	1	1	3	5	1
Skarv Idun Tunge	23.8 %	0	0	0	0	0	0	0	0	0	0
PL212E Ærfugl Nord Base	30.0 %	0	0	3	4	1	0	0	3	4	1
Skarv Ærfugl	23.8 %	6	7	37	49	12	8	11	54	73	17
Skarv Ærfugl Infill A02	23.8 %	1	2	12	15	4	2	3	16	21	5

Reserves pr 31.12.2024	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe
	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Tambar Base	55.0 %	0	0	0	1	0	1	0	0	2	1
Ula Base	80.0 %	2	0	0	2	2	3	0	0	3	3
Hod Base	90.0 %	23	1	4	28	25	28	2	5	34	31
Valhall Base	90.0 %	100	7	18	125	112	114	8	21	143	129
Johan Sverdrup Base	31.6 %	1059	20	37	1116	352	1374	26	48	1448	457
Oda Base	15.0 %	1	0	0	1	0	1	0	0	1	0
Enoch	2.0 %	0	0	0	0	0	0	0	0	0	0
Total, mmboe		**1389**	**55**	**181**	**1625**	**675**	**1783**	**71**	**236**	**2090**	**855**
					Approved for development						
Frosk Attic	80.0 %	4	0	0	4	3	6	0	0	6	5
Gekko Blowdown	80.0 %	2	0	16	17	14	2	0	19	21	17
Kameleon Gas Cap Blow Down	80.0 %	1	0	6	7	5	2	0	17	19	15
Edvard Grieg IOR 2025 A-09	65.0 %	2	0	0	2	1	5	0	1	5	4
Edvard Grieg IOR 2025 A-19B	65.0 %	1	0	0	2	1	3	0	0	3	2
Solveig Ph2	65.0 %	16	3	4	23	15	29	4	5	38	25
Symra	50.0 %	17	2	3	22	11	39	4	7	50	25
PL127C Alve Nord Development	68.1 %	2	2	7	11	7	9	6	19	33	23
PL159D Idun Nord Development	23.8 %	0	0	6	6	2	0	1	8	9	2
PL942 Ørn Development	30.0 %	1	1	21	24	7	2	3	48	54	16
Skarv Tilje Infill A05	23.8 %	3	1	6	10	2	3	2	9	14	3
Tambar East K5 Sidetrack	46.2 %	2	0	0	3	1	4	0	1	5	2
Tambar K-3 Recompletion	55.0 %	1	0	0	1	1	1	0	0	1	1
Ula WAG from K-5B	80.0 %	0	0	0	0	0	0	0	0	0	0
Fenris	77.8 %	28	4	42	73	57	62	7	84	154	120
Valhall PWP	90.0 %	35	3	8	46	42	54	5	13	71	64
Frigg Gamma Delta Development	87.7 %	45	1	4	50	44	79	1	8	88	77
Frøy Development	87.7 %	21	1	3	24	21	31	1	7	40	35
Fulla Development	47.7 %	3	3	23	29	14	5	6	41	52	25

Reserves pr 31.12.2024	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe
	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Krafla/Askja Development	50.0 %	68	21	58	147	73	106	40	107	253	126
Langfjellet Development	87.7 %	11	3	3	17	15	26	8	7	41	36
Lille Frigg Development	47.7 %	2	2	6	10	5	3	4	12	19	9
Rind Development	87.7 %	28	2	11	42	37	41	3	16	59	52
Johan Sverdrup RMLT 2025	31.6 %	2	0	0	2	1	2	0	0	2	1
Johan Sverdrup WAG	31.6 %	65	-9	-14	42	13	88	-7	-11	69	22
Verdande Development	7.0 %	20	0	3	24	2	29	1	6	35	2
Total, mmboe		**377**	**42**	**217**	**635**	**392**	**629**	**88**	**424**	**1142**	**708**
Justified for development											
Valhall Flank West V-1 and V-10 Infills	90.0 %	3	0	1	4	3	5	0	1	6	6
Total, mmboe		**3**	**0**	**1**	**4**	**3**	**5**	**0**	**1**	**6**	**6**
Total reserves											
Total, mmboe		**1769**	**96**	**399**	**2264**	**1071**	**2417**	**160**	**661**	**3238**	**1568**

Figure 2.3: **Aker BP net 1P and 2P reserves as of 31 December 2024 per field and area**

Reserves pr 31.12.2024	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Gross Oil	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**	**Gross Oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**
	(mmbbl)	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**
Alvheim, incl. Boa, KEG/Gekko BD and Kam. BD	49	0	39	89	70	60	0	58	118	93
Bøyla	9	0	1	10	8	13	0	1	15	12
Skogul	1	0	0	1	1	4	0	0	4	3
Tyrving	21	0	0	21	13	24	0	1	24	15
Vilje	3	0	0	3	1	7	0	0	7	3
Volund	3	0	0	4	4	5	0	1	6	6
Alvheim Area	**87**	**0**	**41**	**127**	**97**	**113**	**0**	**61**	**173**	**131**
Edvard Grieg	62	4	7	72	47	78	5	9	91	59
Hanz	2	0	1	3	1	4	0	1	6	2
Ivar Aasen	26	2	6	34	12	32	3	9	44	16
Solveig	43	7	10	60	39	67	8	12	87	57
Symra	17	2	3	22	11	39	4	7	50	25
Troldhaugen	0.1	0	0	0	0	0	0	0	0	0
Grieg / Aasen Area	**150**	**15**	**27**	**191**	**110**	**220**	**20**	**38**	**278**	**159**
Skarv (incl. Gråsel and Idun Tunge)	5	8	39	52	12	7	9	48	64	15
Ærfugl (Incl. Ærfugl Nord)	7	10	52	69	17	10	15	73	98	24
Alve Nord	2	2	7	11	7	9	6	19	33	23
Idun Nord	0	0	6	6	2	0	1	8	9	2
Ørn	1	1	21	24	7	2	3	48	54	16
Skarv Area	**15**	**21**	**124**	**161**	**45**	**28**	**34**	**197**	**258**	**80**
Tambar	1	0	0	1	1	2	0	0	3	2
Tambar East	2	0	0	3	1	4	0	1	5	2
Ula	2	0	0	3	2	3	0	0	3	3
Ula Area	**6**	**0**	**1**	**7**	**4**	**9**	**1**	**1**	**11**	**6**
Fenris	28	4	42	73	57	62	7	84	154	120
Hod	23	1	4	28	25	28	2	5	34	31

Reserves pr 31.12.2024	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross gas	Gross oe	Net oe
	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Valhall	138	10	27	175	157	173	13	35	221	199
Valhall Area	**188**	**15**	**73**	**275**	**239**	**263**	**22**	**124**	**409**	**349**
Hugin	105	6	22	133	116	177	13	38	228	200
Fulla	4	6	29	39	18	8	10	53	71	34
Munin	68	21	58	147	73	106	40	107	253	126
Yggdrasil	**177**	**33**	**108**	**318**	**208**	**290**	**63**	**198**	**552**	**360**
Johan Sverdrup	**1126**	**11**	**22**	**1159**	**366**	**1464**	**19**	**37**	**1520**	**480**
Oda	1	0	0	1	0	1	0	0	1	0
Enoch	0	0	0	0	0	0	0	0	0	0
Verdande Development	20	0	3	24	2	29	1	6	35	2
Other	**21**	**0**	**3**	**25**	**2**	**30**	**1**	**6**	**37**	**3**
Total	**1769**	**96**	**399**	**2264**	**1071**	**2417**	**160**	**661**	**3238**	**1568**

An oil price of USD 77 per barrel for 2025, USD 71 per barrel for 2026-2035, and USD 66 per barrel for subsequent years has been used to estimate reserves. Sensitivity analysis with low and high case oil prices of USD 41 per barrel and USD 92 per barrel, respectively, have been conducted by AGR. The low-price scenario led to a reduction of approximately 50 percent in total net proven (1P/P90) reserves and 27 percent in net proven plus probable (2P/P50) reserves. In contrast, the high oil price scenario resulted in a marginal increase in reserves of less than one percent both for the proven (1P/P90) and proven plus probable (2P/P50) estimates.

Changes from the 2023 reserves report are summarised in Table 2.4. The primary reasons for the increase in net reserve estimates (excluding produced volumes) are enhanced oil recovery (IOR) activities across most fields and minor revisions to previous estimates for Alvheim and Yggdrasil.

On the downside, reserves were reduced for Valhall, mainly due to producing well failures, and for Edvard Grieg, owing to a steeper-than-expected production decline following produced water breakthrough.

Note that gas volumes (starting last year) are reported at a fixed energy content of 40 MJ per standard cubic metre (Sm^3).

Figure 2.4: **Aggregated reserves, production, developments, acquisitions, IOR, extensions and revisions**

	On production		Approved for development		Justified for development		Total	
Net attributed million barrels of oil equivalents (mmboe)	**1P**	**2P**	**1P**	**2P**	**1P**	**2P**	**1P**	**2P**
Balance as of 31.12.23	710	985	398	709	19	22	1127	1716
Production	-160	-160	0	0	0	0	-160	-160
Transfer	18	30	0	-8	-19	-22	0	0
Revisions	106	0	-13	-5	0	0	93	-5
IOR	0	0	7	12	3	6	10	17
Discovery and Extensions	0	0	0	0	0	0	0	0
Acquisition and sale	0	0	0	0	0	0	0	0
Balance as of 31.12.24	675	855	392	708	3	6	1071	1568
Change 2024-2023	-35	-130	-6	-1	-15	-16	-56	-147

The Tyrving field and the Hanz field started production in 2024 and were transferred to the "On production" resource category, along with new wells on Alvheim and Skarv.

Johan Sverdrup remains the company's most significant field, contributing approximately 30 percent of Aker BP's 2P reserves.

Total net production for Aker BP averaged 439 thousand barrels of oil equivalent per day (mboepd), or approximately 160 million barrels of oil equivalent (mmboe) in 2024. This is higher than the initial forecast for the year, primarily due to better-than-expected production from the Johan Sverdrup field.

Please note that these production numbers are approximate, based on actual production data for the first nine months of the year and a forecast for the final three months of 2024. The final figures may vary slightly.

3. Description of reserves

The following chapter describes the reserve assessment from all producing fields.

Figure 3.1: **Our assets and offices**

3.1 PRODUCING ASSETS

3.1.1 Alvheim (PL036C, PL036G, PL088BS, PL203)

Alvheim is an oil and gas field located in the central part of the North Sea, to the west of Heimdal and near the UK sector border. The field encompasses licences PL203, PL088, and PL036C. The producing Alvheim structures include Kneler, Kameleon, East Kameleon, Boa (with a 11.65 percent on the UK side), Viper, Kobra, Kobra East, and Gekko. Kobra East and Gekko were brought on production in 2023. Sales gas from the Vilje field (PL036D) is marketed by PL203 through a commercial agreement. The water depth in the area ranges from 120 to 130 metres. First production was in 2008.

Discovery

The Alvheim field was discovered in 1998 with well 24/6-2, which encountered oil and gas in sandstones in the Heimdal Formation in the Kameleon structure. The gross gas and oil columns were 52 metres and 17 metres, respectively. Further discoveries in the Heimdal Formation were 24/6-4 (Boa structure) and 25/4-7 (Kneler structure) in 2003.

The Kobra discovery was made in 1997 with well 25/7-5, which proved oil in the Hermod Formation, and the Viper discovery was made in 2009 with well 25/4-10S, which proved oil in Hermod Formation injection sands.

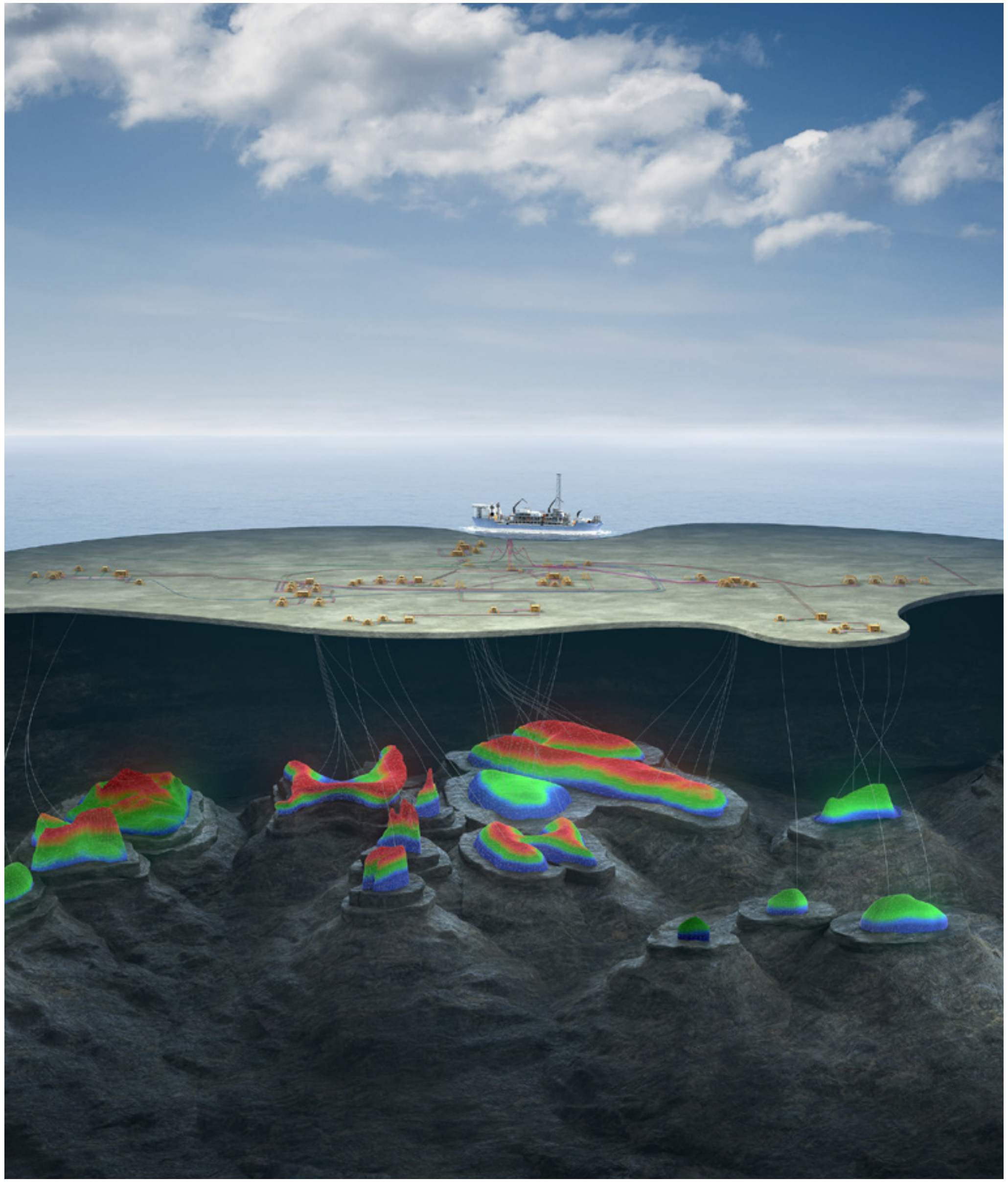
The Gekko oil and gas discovery was made in 1974 by well 25/4-3 in the Heimdal Formation. Kobra East was discovered in 2016 through drilling an extension of the Kobra well 24/9-P-8 AY1H.

Reservoir

The Alvheim reservoir consists of high porosity, high permeability sandstones from the Palaeocene Heimdal Formation. The reservoir quality is generally excellent, although there are some local variations. The sand was deposited as submarine fan (turbidite) deposits, sources from the East Shetland Platform.

The Viper and Kobra structures are composed of high-quality, remobilised Hermod sands. Viper is an injection feature cutting through the overlying stratigraphy (dyke), while the Kobra sands consist of injection features mainly sub-parallel to the stratigraphy (sills). A common oil-water contact (OWC) has been drilled, and it is likely that Viper and Kobra communicate both in the oil leg and the underlying aquifer.

The Gekko reservoir is composed of Heimdal Formation sands, situated in a submarine fan system south of, and analogous to, the Alvheim reservoir. Gekko is defined by two subtle four-way closures: Gekko South, with blocky stacked sandy turbidites and a high net-to-gross ratio, and Gekko North, which contains channel sands interbedded with finer-grained deposits. The reservoir is in pressure communication throughout the Heimdal formation and with the large underlying aquifer.



The Kobra East reservoir is analogous to both Viper and Kobra, consisting of a main injection sill overlain by dykes and wings. The reservoir properties are excellent.

Development

The Alvheim field is developed with a production vessel, the "Alvheim FPSO", and subsea wells. The oil is stabilised and stored on the production vessel before being exported by tanker. Processed rich gas is transported via 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 Inflow Control Devices (ICDs), and more recently, Autonomous Inflow Control Devices (AICDs). Several of the wells are multi-lateral. The AICDs are used to manage water coning from the aquifer and gas coning from the gas cap, particularly in the thin oil rim reservoirs. The recovery method employed is bottom aquifer drive.

Viper and Kobra were developed in 2016 with one horizontal well in Viper and a bilateral well in Kobra, with one lateral in the main sill and another lateral shallower in the injection dykes (Kobra shallow). These wells are tied back to the Volund manifold system.

The Kobra East and Gekko (KEG) fields were developed in 2023 with a subsea tie-back to the Alvheim FPSO via the Kneler B manifold. Gekko is produced through a four-slot manifold in the south, using two trilateral wells, and a two-slot manifold in the north with a single trilateral well. The Gekko blowdown phase will be produced through two sidetracks. The main drainage mechanism for the oil phase is natural pressure depletion, supported by a strong aquifer drive and some gas cap expansion. To effectively drain the six-seven metre oil column, each of the nine laterals has a completion length of around 4000 metres (with AICDs) and is placed approximately two metres below the gas-oil contact.

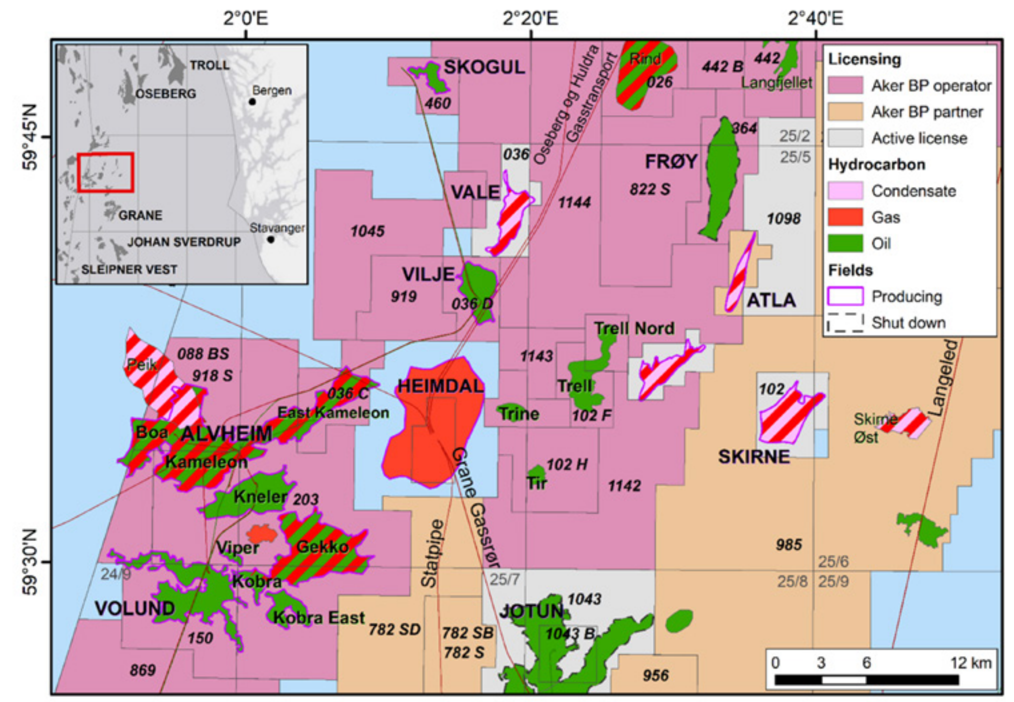
Kobra East is produced via a trilateral well drilled from the same four-slot template as Gekko South. Pressure support is provided by the aquifer, and the Kobra East well will continue production during the Gekko gas blowdown phase.

Status

The number of active production wells on the Alvheim field are as follows: Boa (4), Kneler (6), Kameleon (4), East Kameleon (2), Viper (1), Kobra (1), Kobra East (1), and Gekko (3).

The recoverable volumes on the Alvheim field are classified as "Reserves; On production" according to the SPE's classification system. Actual production in 2024 was slightly below the 2P estimate for the year, primarily due to a higher gas-to-oil ratio (GOR) in the newer wells that came on stream. This includes the KEG wells, which started production at the end of 2023, and the infill well L5/EK5, which started production in May 2024.

Figure 3.2: **Alvheim field location map**



The Alvheim East Kameleon infill well, L5/EK5, was brought on production in May 2024, and the recoverable volumes are now classified as "Reserves; On production".

Blowdown of the Kameleon gas cap is assumed to start in May 2036. The recoverable volumes from the Kameleon gas cap blowdown are classified as "Reserves; Approved for development".

The blowdown of the Gekko gas cap is assumed to start in January 2031. The recoverable volumes from the Gekko blowdown are also classified as "Reserves; Approved for development".

Aker BP is the operator of the Alvheim field, holding an 80 percent working interest in the Norwegian part, with ConocoPhillips Skandinavia AS as a partner, holding 20 percent interest. The Boa reservoir straddles the Norway-UK median line, and is unitised with NEO Energy, the owner on the UK side. Aker BP's interest in the total Boa unit is 70.92 percent.

3.1.2 Vilje (PL036D)

The Vilje field is an oil field situated 5 km northeast of the Heimdal production facility, within block 25/4 and licensed under PL036D in the North Sea. The reservoir is located at a depth of approximately 2200 metres true vertical depth measured from mean sea level (TVD MSL), with a water depth in the area of around 120 metres. Production commenced in 2008.

Discovery

The Vilje field was discovered in 2003 by well 25/4-9 S. The reservoir, located in the Heimdal Formation, was encountered at a depth of 2135 metres TVD MSL, with 61 metres of gross sand (56 metres net). The sand exhibits very good reservoir properties and was found to be oil-bearing with undersaturated oil.

Production from the nearby Heimdal and Frigg fields had caused a depletion of the regional aquifer by approximately 18 bars. Based on the well results, the oil-water contact (OWC) has been determined at various levels between 2195 and 2198 metres TVD MSL. The current OWC is expected to be influenced locally by the depletion and ongoing production in the area.

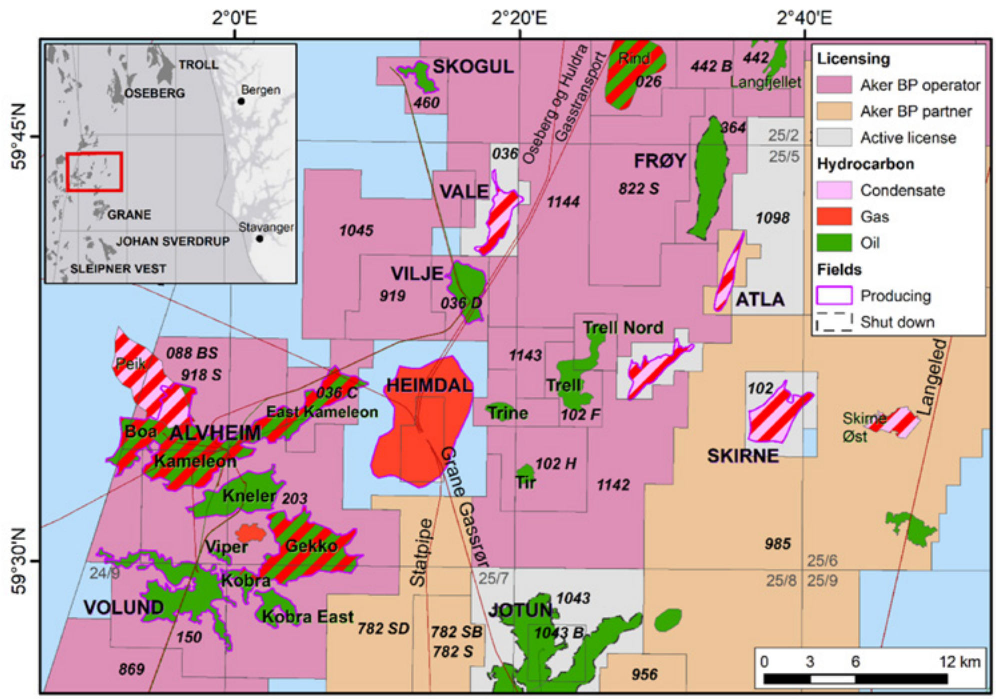
Reservoir

The Vilje field is a flat low-relief fan of Heimdal depositional system. The field has two separate structures: Vilje Main and Vilje South. The reservoir is a turbidite deposit, in the Heimdal Formation from the Palaeocene at about 2150 metres TVD MSL. The reservoir interval is divided into three reservoir zones – R1, R2 and R3 – where R1 and R3 are clean sands while R2 is a fine-grained muddy layer which acts 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.

Figure 3.3: **Vilje location map**



Status

The recoverable volumes in Vilje are classified as "Reserves; On production" (SPE's classification system). After Skogul came on stream in March 2020, the main production strategy has been to optimise the combined Vilje and Skogul production in the pipeline. There is a commercial agreement between the Skogul and Vilje licenses, where Skogul compensates for deferred Vilje production. The actual production in 2024 from the Vilje reservoir is in good alignment with the 2P estimate for 2024.

Aker BP holds a 46.904 percent interest in the licence and serves as operator. The other licence partners are DNO Norge AS, holding a 28.853 percent interest, and ORLEN Upstream Norway AS with a 24.243 percent interest.

3.1.3 Volund (PL150)

The Volund field is an oil field located eight km south of the Alvheim field in block 24/9 licensed under PL150 in the North Sea, see Figure 3.4. The reservoir depth is about 1900 metres TVD MSL and the water depth in the area is about 120-130 metres. Production started in April 2010.

Discovery

The Volund field was discovered in 1994 by well 24/9-5. Oil was encountered in the Intra Balder Formation sandstones between 2011 to 2018 metres TVD MSL (oil down to). The discovery was appraised by wells 24/9-6 and 24/9-7, which confirmed a field-wide OWC at 1995 metres TVD MSL and a gas-oil contact (GOC) at 1891 metres TVD MSL.

Reservoir

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

Development

The field is developed with six production wells and one injection well, tied back subsea to the Alvheim FPSO. The initial development included three production wells targeting the approximately 100-metre oil column in the wings, supported by one water injector in the sill, alongside natural water drive. The first infill well started production in 2013, followed by two additional infill wells that started production in 2017. Two of the original production wells have been sidetracked, one in 2019 and the other in 2021.

Status

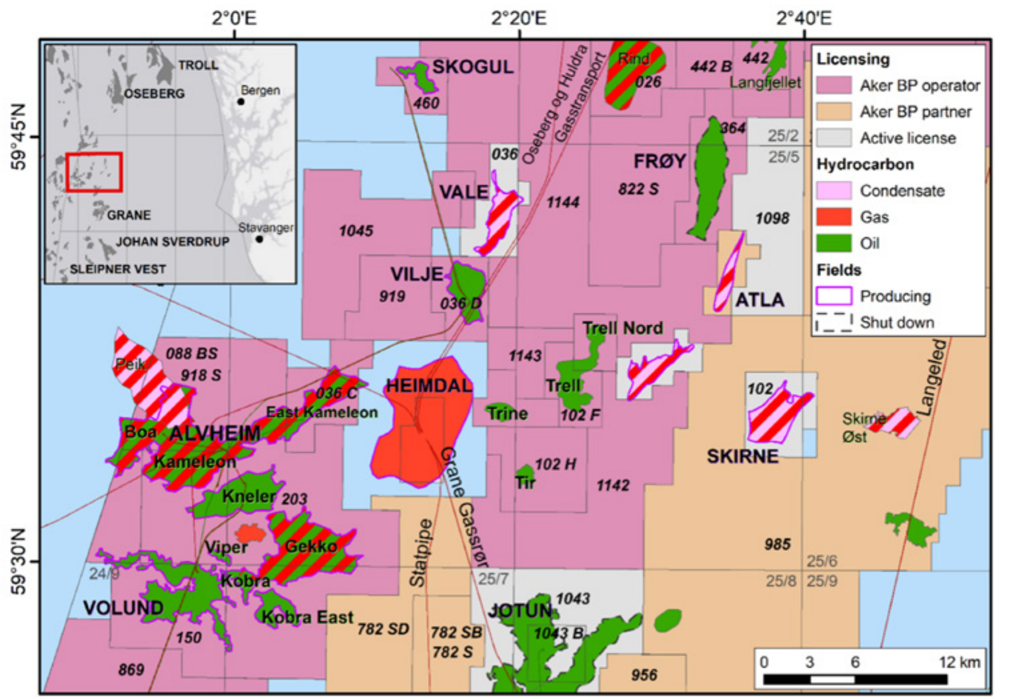
The recoverable volumes on Volund are classified as "Reserves; On production" (SPE's classification system). The actual production in 2024 was in line with the 2P estimate for 2024.

Aker BP is the operator and holds a 100 percent interest in Volund after the merger with Lundin Energy Norway AS.

3.1.4 Bøyla (PL340)

The Bøyla field consists of two reservoirs (Bøyla and Frosk) located in PL340, block 24/9 in the central part of the North Sea, 15 km southwest of the Volund field. Water depth is 120 metres. The well M-01 BH, on the northwestern flank, started to produce on 19 January 2015 from the Bøyla reservoir and M-4 started production from Frosk in August 2019. The location of the Bøyla field is shown in Figure 3.5.

Figure 3.4: **Volund location map**



An infill well in the Frosk reservoir, Frosk Attic (M-7), was approved for development in 4Q 2024 with planned production start 4Q 2025.

Discovery

Bøyla was discovered in 2009 by well 24/9-9 S. The initial discovery name was "Marihøne A". The well proved undersaturated oil at normal pressure with an OWC at 2071 metres TVD MSL. Subsequent pilot and development wells have confirmed the OWC across the field.

Frosk was discovered in 2018 by the 24/9-12 S well and sidetrack 24/9-12 ST2. It was later appraised by wells 24/9-12 A / AT2 and 24/9-15 A. The wells penetrated a 40-metres oil-bearing injectite sand-complex from the Upper Palaeocene to Lower Eocene in the Intra Hordaland Group. The reservoir was penetrated at 1800 metres TVD MSL. The GOC was defined at 1786 metres TVD MSL and OWC at 1861 metres TVD MSL. The oil is biodegraded to a relatively low quality.

Reservoir

The Bøyla structure is a flat low-relief Eocene turbidite fan deposit. The reservoir is within the Palaeocene/Eocene Hermod Sandstone Formation, completely encased within Sele Formation shales. The Hermod Sandstone Formation is interpreted as sediment gravity flows sourced from the East Shetland Platform, deposited in a basin floor setting. Hermod sandstones have presumably filled bathymetric lows created by the underlying Heimdal Formation.

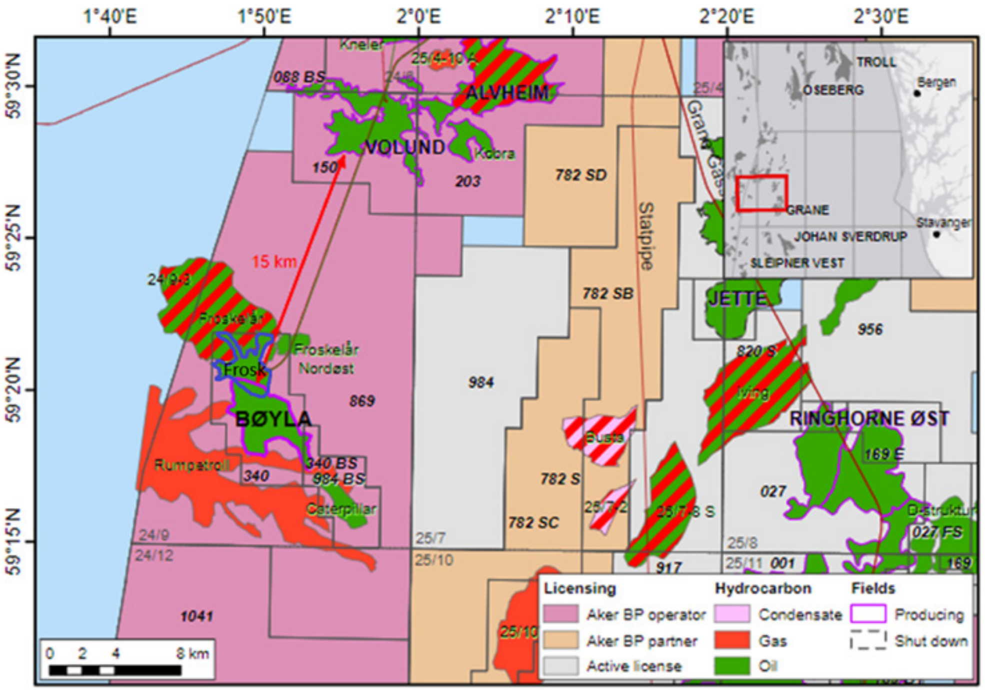
Two major depocenters have been recognised in the Bøyla reservoir, one in the west, and one in the east. Connectivity between these two parts of the reservoir is uncertain. The pre-drilled wells confirmed a consistent OWC. Injection testing of the single water injector has proved sufficient injectivity 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 present on a production time scale.

The Frosk injectite sands are believed to have been injected into the Sele, Balder and Hordaland Formations from the underlying Odin sand. Odin is a 70-metres thick sand body in the Balder Formation (24/9-3). Frosk main sand consists of a dyke coming from the crest of Odin and levelling out as a thick sill in the Hordaland Formation. Around the main Frosk injectite, we find several small dykes and sills, acting as "fingers". The injection process has enhanced the reservoir properties, with average porosity of 32 percent and permeabilities up to 10 Darcy. The main sill is homogeneous, with a net-to-gross close to 100 percent.

Development

The Bøyla field is a four-slot subsea template development. Two long horizontal producers and one deviated water injector is targeting the Bøyla reservoir and three wells with six branches targeting the Frosk injectites. The fluid is transported through a 26-km pipe-in-pipe flowline to the Kneler A subsea template, which is further tied back to the Alvheim FPSO. Gas lift is required in the producers. The main recovery mechanism is water injection in Bøyla and aquifer pressure support in Frosk.

Figure 3.5: **Bøyla location map**



Production from well 24/9-M-4, the Frosk Test Producer, also called FTP, commenced in August 2019. The test production well is a horizontal bilateral well targeting Frosk Main injectite sands and Upper Zone. The main bore was permanently shut-in in March 2021 due to sand production. The well is producing through the Bøyla subsea system to the Alvheim FPSO.

The Frosk Development project was brought on production in 2023 via two subsea production wells to drain further areas in the field. Drilling was completed in December 2022. The two wells brought on stream include one horizontal production well (24/9-M-5H) targeting the northern dyke area and one horizontal bilateral producer (24/9-M-6 Y1H and Y2H) targeting the eastern areas of the Frosk Main injectite.

Frosk Attic producer is planned as a tri-lateral well and will target volumes left behind from M-4 main bore in addition to undrained areas and attic oil accessible from the same reservoir entry. The well is planned with similar design as recent Alvheim and Frosk wells.

Status

The recoverable volumes in Bøyla (which includes the volumes in Frosk reservoir as well) are classified as "Reserves; On production" (SPE's classification system). The actual production in 2024 has been in very good alignment with the 2P estimate for 2024.

Frosk Attic, the infill well that has been approved for development, is planned to come on stream in 4Q 2025. The recoverable volumes are classified as ""Reserves; Approved for development" (SPE's classification system.)

Aker BP is operator and holds an 80 percent interest in Bøyla with Concedo AS as partner (20 percent interest).

3.1.5 Skogul

The Skogul oil field is located approximately 40 km 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. Figure 3.6 shows the location of the discovery. The water depth is about 107 metres in the area, and the crest of the structure is estimated to be at 2097 metres TVD MSL.

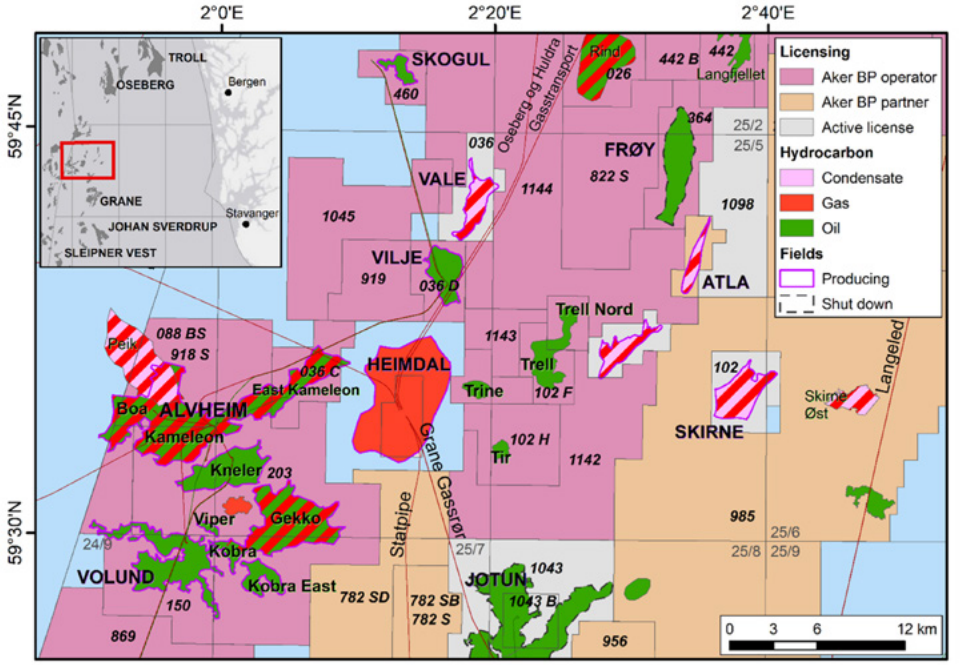
Discovery

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 with excellent reservoir quality in Upper Balder-Frigg Formation sandstones. Vertical well 25/1-11 R was drilled on a structural high with a strong amplitude anomaly, encountering a 13-metres oil column and an oil-water contact (OWC) was identified. A deviated (29°) sidetrack well, 25/1-11 A, 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 2106 metres TVDSS and a 12-metres oil column.

Reservoir

The reservoir consists of Eocene Upper Balder and Frigg Formation sandstones with good properties. The reservoir sandstones were derived from the East Shetland Platform to the West and deposited from deep marine turbidity currents as part of the Frigg submarine fans. Average NTG in the main producing intervals in the Skogul reservoir is high (~92%), average porosity is ~31% and permeabilities are around 1 Darcy. The reservoir was depleted to 8 percent (~18 bar) below hydrostatic pressure at the time of discovery (2010). This is a result of the regional production history of which the Frigg field production and subsequent re-pressurisation are the most significant factors. Pressure measurements taken in the development wellbores (2019) show a uniformly increased pressure by ~3 bar since 2010. This is a positive indication that an aquifer is present and gives pressure support to the Skogul reservoir.

Figure 3.6: **Skogul location map**



Development

Skogul is developed as a tie-back to the Alvheim FPSO via the Vilje template and pipeline. A bilateral producer was drilled and completed between July 2019 and January 2020. It is tied to a two-slot subsea template. The drive mechanism is depletion and natural aquifer support.

Status

Skogul field recoverable volumes are classified as “Reserves; On production” (SPE’s classification system). After Skogul came on stream in March 2020, the main production strategy has been to optimise the combined Vilje and Skogul production in the pipeline. There is a commercial agreement between the Skogul and Vilje licences, where Skogul compensates for deferred Vilje production. The actual production in 2024 was higher than the 2P estimate for 2024, primarily driven by exceptional performance of the Skogul well.

Aker BP is operator and holds 65 percent interest in the Skogul field. The remaining 35 percent is held by ORLEN Upstream Norway AS.

3.1.6 Tyrving

The Tyrving field consists of the three discoveries Trell, Trell North and Trine. Trell and Trell North are located in block 25/5, production license PL102F/G. Trine is located in block 25/4, production license PL036E/F. Tyrving is situated in the central part of the Norwegian sector in the North Sea, east of the Heimdal field. Tyrving is unitized. A location map is shown in Figure 3.7. Water depth in the area is 119 metres and the reservoir is located between 2100-2200 metres TVD MSL. The PDO for Tyrving was submitted to the Ministry of Petroleum and Energy in August 2022 and development drilling commenced January 2024.

Discovery

The Trine discovery well, 25/4-2, was drilled in 1973. The well discovered oil in Late Palaeocene Heimdal Formation sandstone. A nine-meter-thick oil column was found from top of the reservoir down to an OWC at 2142.5 metres TVD MSL. The Trell discovery well, 25/5-9, was drilled in 2014. This well discovered a 21m oil column in the Heimdal Formation with an OWC at 2178 metres TVD MSL. Additionally, an exploration pilot well was drilled during the development campaign on Tyrving to prove volumes in the Trell North structure. The well, 25/5-H-1 AH, discovered an 18 metres hydrocarbon column with an OWC at 2174 metres TVD MSL.

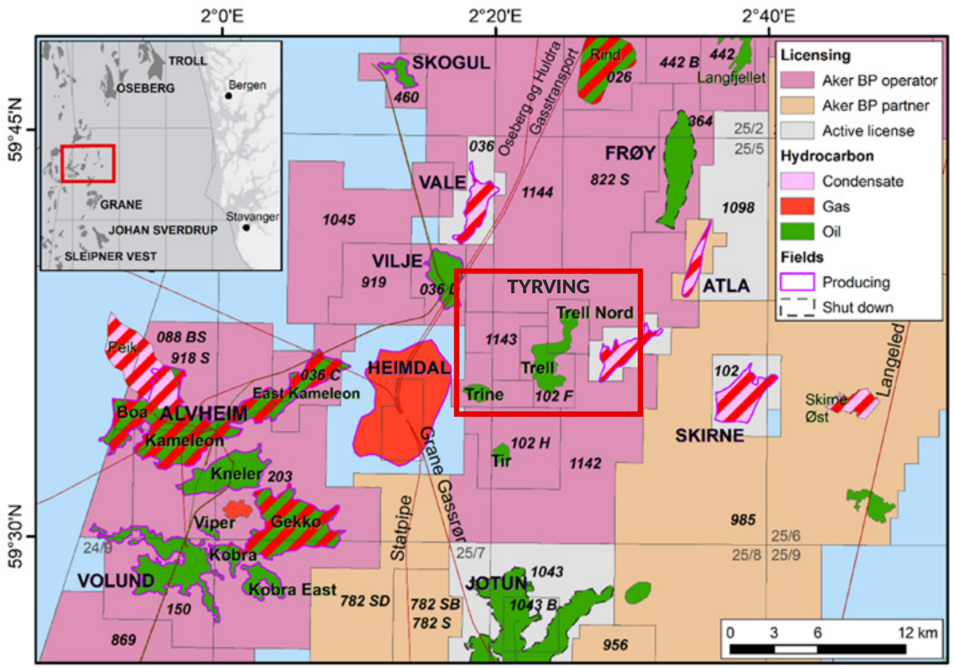
Reservoir

The Tyrving field consists of three relatively small four-way closures filled with oil, each structure only 1-2 km across and located close to one another. The reservoir is the Late Palaeocene Heimdal Formation and consists of turbidite sandstones with excellent reservoir properties; NTG above 90 percent, porosity of 26 percent and permeabilities above 1D. The Heimdal sandy sequence in the Tyrving area comprises a 300 to 400-metres thick package and the oil accumulations are connected to a large aquifer.

Development

The development of the Tyrving field consists of one three-branch well in Trell, a single lateral well in Trell North, and a bilateral well in Trine. The completions feature open-hole wire-wrapped inflow control device (ICD) screens. Production from each branch is hydraulically controlled with inflow valves. There are two 2-slot templates, one for Trell and Trell North and another for Trine. Oil is transported via a

Figure 3.7: **Tyrving location map**



15-kilometer-long pipeline to the East Kameleon Pipeline End Manifold (PLEM), where gas is also sourced for downhole gas lift. Tyrving shares pipeline capacity with the East Kameleon field, which is connected to the Alvheim FPSO.

Oil production is supported by water drive from the Heimdal aquifer, which has been effective in most fields in the area. Downhole gas lift, pressure and temperature gauges, as well as multiple in-well tracers, have been implemented for each lateral. Production is monitored using subsea multi-phase flow meters on North Tyrving and South Tyrving manifolds. Reservoir pressure has been measured slightly above 200 bar, and temperature is approximately 80°C. The reservoir pressure may continue to rise due to regional aquifer equilibration following the shut-in of the Heimdal field. Both the oil bubble point (around 60 bar) and gas-oil ratio (around 40 Sm^3/Sm^3) are very low across all three accumulations, though the fluids are not identical. The oil viscosity is light, at 0.9 centipoise (cP) for Trell and 2.0 cP for Trine, while viscosity for Trell Nord is yet to be determined.

Status

All three Tyrving wells commenced production in the second half of 2024, with first oil achieved on 3 September 2024. The recoverable volumes for Tyrving, which includes the Trell, Trell North, and Trine discoveries, are classified as "Reserves; On production" (SPE's classification system). Actual production in 2024 exceeded the 2P estimate, primarily due to an accelerated start-up of all three wells compared to the original schedule.

Aker BP holds a 61.26 percent interest in the licence and serves as the operator. The other licence partners are Petoro AS, with a 26.84 percent interest, and ORLEN Upstream Norway AS, holding an 11.90 percent interest.

3.1.7 Ivar Aasen Unit (PL001B, PL242, PL338BS, PL457)

The Ivar Aasen field is located in the North Sea, approximately 8 km north of the Edvard Grieg field and around 30 km south of the Grane and Balder fields. The field contains both oil and free gas and consists of two accumulations: Ivar Aasen and West Cable. These accumulations span multiple licences and have been unitised into the Ivar Aasen Unit. Production from Ivar Aasen commenced on 24 December 2016. The water depth in the area is approximately 110 metres, and the main reservoir at Ivar Aasen is located at a depth of about 2400 metres TVD MSL.

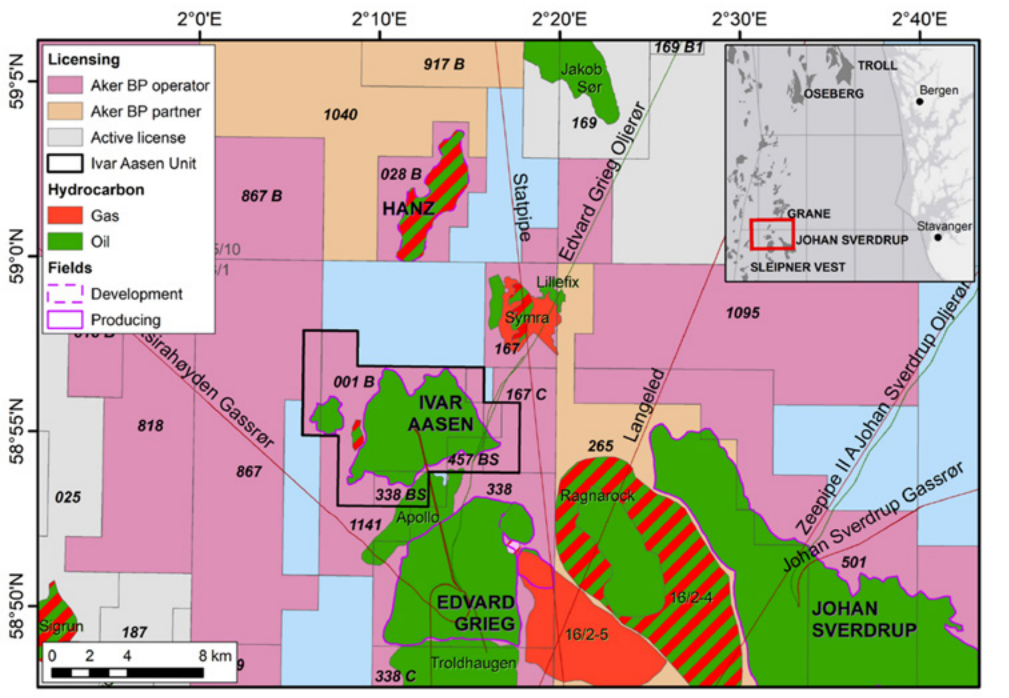
Discovery

Ivar Aasen was discovered with well 16/1-9 in 2008, confirming the presence of oil and gas in Jurassic and Triassic sandstones. An earlier exploration well, 16/1-2, drilled in 1976 within the structural closure, was initially classified as dry but was later re-evaluated and reclassified as an oil discovery. The West Cable accumulation was discovered with well 16/1-7 in 2004, confirming oil in Jurassic sandstones.

Reservoir

The two accumulations are located on the Gudrun Terrace, situated between the Southern Viking Graben and the Utsira High. The reservoir sands are fluvial and shallow marine deposits from the Late Triassic to Late Jurassic. 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, whereas the West Cable structure holds undersaturated oil.

Figure 3.8: **Ivar Aasen Unit and Hanz location map**



Development

The Ivar Aasen field is developed with a steel jacket, which includes living quarters and process facilities, situated at a water depth of 110 metres. The platform features dry wellheads, and wells are drilled using a jack-up rig. The well stream is partially processed on the platform before being transported through pipelines to the Edvard Grieg installation for final stabilisation and export. Edvard Grieg also supplied power to Ivar Aasen until a joint power-from-shore solution was established in December 2022.

The Ivar Aasen platform has a total of 20 slots, of which 12 are producer slots and 8 injector slots. The drainage strategy for the Ivar Aasen structure relies on water injection for pressure maintenance. Currently there are 12 producers and 8 injectors (including two redrills) targeting the Ivar Aasen structure.

The production wells are completed with mechanical sand control and ICD completions. The two most recent producers drilled are installed with sliding sleeves at the heel of the wells. One well, D-18, is completed with fishbone technology. Three producers are multilateral wells with dual branch control. The injectors have cemented perforated liners, except three horizontal injectors which are completed with screens, FloFuse technology, and sliding sleeves.

Status
The PDO for the Ivar Aasen area was approved in early 2013. The field came on stream on 24 December 2016, in line with the development plan. All initially planned wells were drilled in the Ivar Aasen and West Cable structures. The development wells in the Ivar Aasen main field performed as expected. Since then, five infill campaigns have been completed, with the most recent campaign drilled in 2022, and the wells coming on stream late in 2022 and early 2023.

Production from West Cable ceased in June 2022 when slot D-9 was redrilled to the Ivar Aasen field. Total oil recovery from the West Cable structure has amounted to 0.15 million standard cubic metres. Cessation of production (CoP) for the Ivar Assen field is expected by the end of 2041. The recoverable volumes for Ivar Aasen are classified as “Reserves; On production” (SPE’s classification system).

Aker BP holds a 36.1712 percent interest in the Ivar Aasen Unit. Other licensees include Equinor Energy AS (41.4730 percent), Sval Energi AS (12.3173 percent), OKEA ASA (9.2385 percent), and M Vest Energy AS (0.8 percent).

3.1.8 Hanz

The Hanz oil field is located in the North Sea, 6 km north of the Ivar Aasen field and around 25 km south of the Grane and Balder fields. Hanz commenced production in April 2024. The water depth in the area is approximately 110 metres and the main reservoir at Hanz is found at about 2400 metres TVD MSL.

Discovery
The Hanz discovery was made by exploration well 25/10-8 in 1997, drilled by Exxon. A production test (DST) was conducted on the discovery well. The Hanz reservoir was further appraised by Aker BP in 2018, through the wells 25/10-16 S, 25/10-16 A and 25/10-16 C.

Reservoir
The Hanz field consists of Upper Jurassic Draupne sandstones at a depth of approximately 2400 metres. The depositional environment is characterised by gravity flow turbidites originating from the Utsira High to the east. The reservoir contains several overlying thin sands, each with a thickness ranging from 1 to 13 metres, separated by thin shale layers. Both the DST, core samples, and logs indicate excellent reservoir quality with highly porous, multi-Darcy sandstone. The reservoir pressure is slightly below hydrostatic. Vertical communication between sand bodies is restricted, while lateral communication is influenced by barriers.

The Hanz Heimdal aquifer reservoir lies about 300 metres above the Hanz Draupne reservoir. The Heimdal reservoir is a highly porous, multi-Darcy, homogeneous sand package, approximately 80 metres thick, extending across a large area of the North Sea. The reservoir pressure is slightly below hydrostatic.

Development
The Hanz field is developed with two subsea wells, which are tied back to the Ivar Aasen platform. Production from the field commenced in April 2024. Hanz is produced through a 14-kilometre pipeline to the Ivar Aasen platform.

The drainage strategy for Hanz involved pressure support from a crossflow water injector, which draws water from the Heimdal aquifer reservoir located approximately 300 metres above the Hanz Draupne reservoir. Both the producer and the crossflow water injector have horizontal well sections exceeding 2000 metres in the Draupne reservoir. The wells are located about 700 metres apart and penetrate all major hydrocarbon sands in the Draupne Horst structure. The producer began production in April 2024, while the injector was opened for crossflow in July 2024.

Status
The Hanz development was sanctioned by the licence in December 2021, and the field came on stream as planned on 20 April 2024. Aker BP holds a 35 percent in the Hanz field, with the remaining shares held by Equinor Energy AS (50 percent) and Sval Energi AS (15 percent).

3.1.9 Edvard Grieg (PL338)

The Edvard Grieg field is located in Block 16/1, PL338, on the western side of the Utsira High, approximately 180 km west of Stavanger, with a water depth of around 109 metres. The top reservoir is at approximately 1850 metres TVD MSL. The PDO for Edvard Grieg was approved in 2012, with production starting in November 2015.

Discovery

The Edvard Grieg field was discovered with well 16/1-8, which proved oil in aeolian sandstone and conglomerates. The field was further appraised by wells 16/1-10 and 16/1-13, with two DSTs performed showing good productivity and improving properties and thickness away from the wells. In 2011, well 16/1-15 proved oil in lower Cretaceous sandstones of excellent reservoir quality, overlaying a porous and fractured basement section. The production test demonstrated very good productivity in both formations. Production history indicates very good lateral communication. Five additional appraisal wells have been drilled on Edvard Grieg, targeting the eastern conglomerates, sands to the west, and proving oil in fractured/weathered basement.

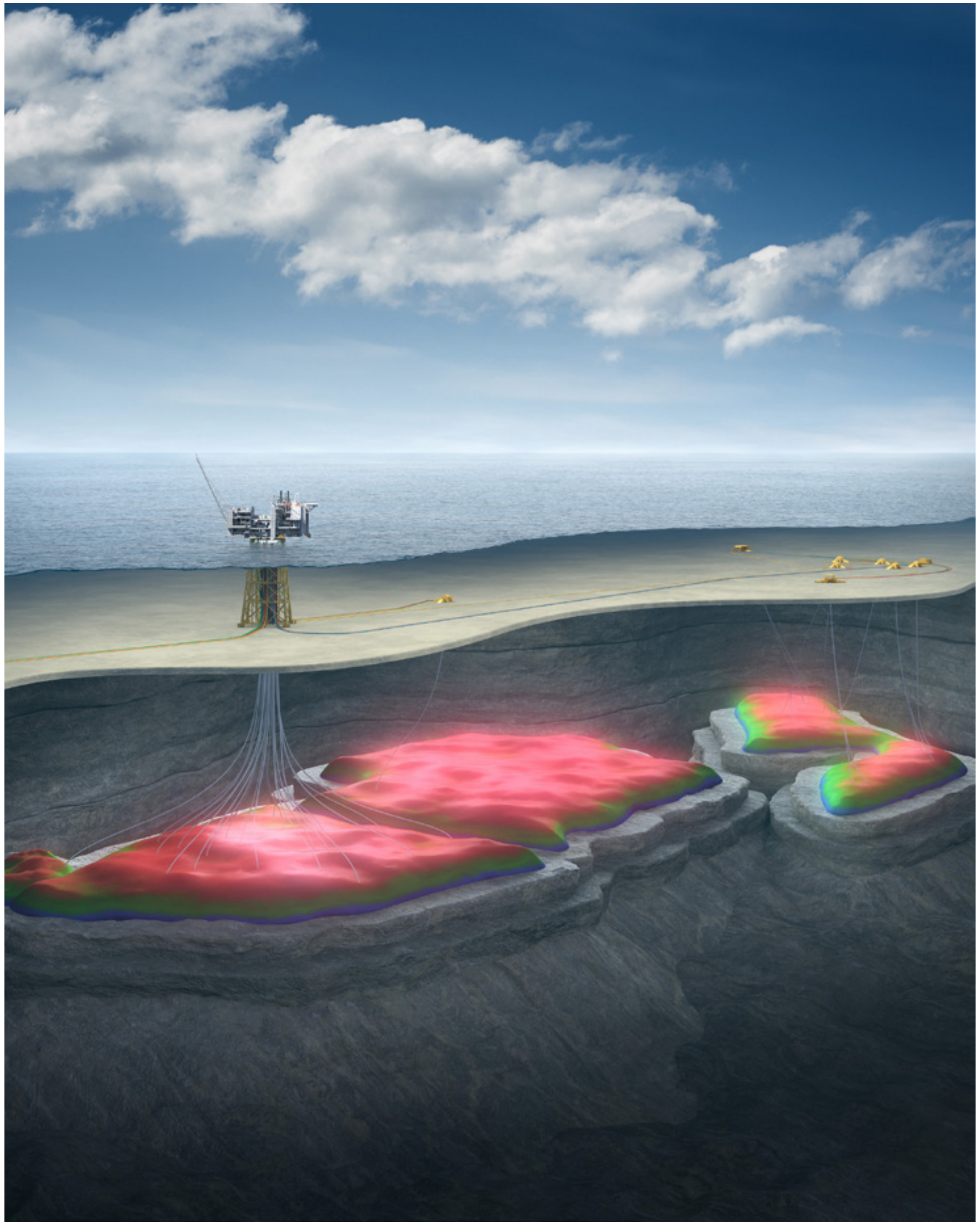
Reservoir

The Edvard Grieg field is a combined structural and stratigraphic trap, containing light and slightly undersaturated oil within various reservoirs. These include bioclastic shallow marine sandstones, aeolian sandstones, fluvial and alluvial sandstones and conglomerates, and weathered granitic basement. The sandstones generally exhibit excellent reservoir quality, while the conglomerates have moderate to poor properties. The basement reservoir, primarily found to the north of the field, exhibits extreme variability in reservoir quality.

Development

The Edvard Grieg field is developed with a PDQ jacket solution, equipped with a total of 20 well slots. A full processing facility is installed on the platform, which is connected to the Oseberg Transport System (OTS) via the Edvard Grieg Oil Pipeline (EGOP) and the Grane Oil Pipeline (GOP), as well as to the Scottish Area Gas Evacuation System (SAGE) via the Utsira High Gas Pipeline (UHGP). The Ivar Aasen, Solveig, and Troldhaugen EWT are currently tied back to the Edvard Grieg platform.

The primary drainage strategy for Edvard Grieg involves voidage replacement water injection to ensure pressure maintenance. To date, 15 producers and four injectors have been drilled, including the IOR 2023 campaign. Additionally, one producer (A-14) is planned for conversion to an injector at the end of this year, increasing the number of injectors to five.



Most of the wells are completed using screens, and three wells are equipped with Fishbones technology. Three of the injectors have cemented liners, and one converted producer is completed with screens. Three of the wells have zonal control using ODIN valves, while two wells in IOR 2023 are completed with sliding sleeves. Two of the wells are dual-branched MLT with branch control. The last MLT well was completed with Manara zonal control in one branch and fishbones in the other.

The first IOR campaign, completed in 2021, consisted of three infill production wells. A second infill campaign was successfully completed in 2023 with three oil production wells. The third infill campaign has been approved, with drilling scheduled to start in February 2025. This campaign includes two additional wells: the first will be drilled from the last existing slot on the Edvard Grieg platform (A-09) and completed with sliding sleeves, and the second will involve a branch addition to the existing A-19 well, using retrofit multilateral technology to create a second branch (A-19Y2).

The Edvard Grieg platform was fully electrified in December 2022.

In addition to the existing tiebacks to Edvard Grieg, Solveig Phase 2 and Symra are planned tiebacks in the future. Symra will be routed through Ivar Aasen prior to reaching Edvard Grieg. These development projects are discussed in a later section.

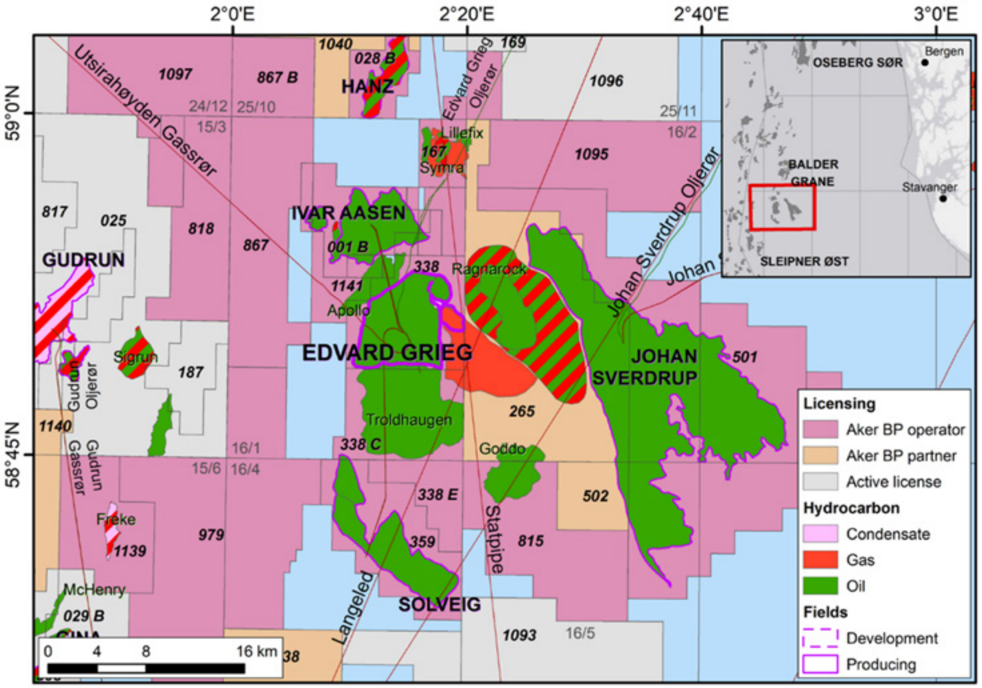
Status

Production at the Edvard Grieg field commenced in November 2015 with two production wells available at startup. Injection started seven months after production. The field has outperformed expectations, mainly due to higher volumes, delayed water breakthrough, and more optimal sweep, as confirmed by 4D seismic data. The reserves estimated at the PDO were produced in 2021, while the field was still on plateau production. Three new producers came on stream in 2021 as part of the IOR 2021 campaign, with results meeting or exceeding expectations. In addition, three new infill wells were drilled in 2023 to mitigate production decline, and the results from this campaign were also in line with expectations.

The recoverable volumes for Edvard Grieg are classified as "Reserves; On production" (SPE's classification system). The estimate of ultimate recovery (EUR) remains unchanged from last year.

The partnership for Edvard Grieg consists of Aker BP as the operator, holding a 65 percent interest, OMV (Norge) AS with a 20 percent interest, and Harbour Energy Norge AS with a 15 percent interest.

Figure 3.9 **Edvard Grieg location map**



3.1.10 Solveig (PL359)

The Solveig field is an oil and gas discovery located on the Utsira High, 190 km west of Stavanger. The distance to the Edvard Grieg field to the north is 15 km. The water depth at the location is around 109 metres. The top reservoir is at approximately 1890 metres TVD MSL. The PDO for Solveig Phase 1 was approved in 2019, and production began in the third quarter 2021.

Discovery & Appraisal

Licence PL359 was awarded in 2006. The first well drilled in the licence, 16/4-5 (2010), was dry but proved oil shows in faulted and fractured, but tightly cemented, granitic basement.

The Solveig discovery was made by the second well, 16/4-6 S, in 2013, and followed by further appraisal through wells 16/5-5 (2013), 16/4-8 S (2014), 16/4-9S (2015) and 16/4-11 (2018) before submission of the Solveig PDO in late 2018. After the PDO, well 16/4-13 ST2 appraised Segment D in 2021.

Reservoir

The Solveig field includes two main reservoir intervals, “Outer Wedge” and “Synrift”, separated by a major, regional unconformity. Both reservoirs are dominated by continental red-bed sandstones with a scarcity of age-diagnostic fossils. The Outer Wedge reservoir is dated late-Permian Rotliegendes Group and the Synrift reservoir is of (late) Devonian (Buchan Equivalent) age. The current understanding of the Solveig field is that the large-scale stratigraphic architecture is controlled by three major, regional unconformities.

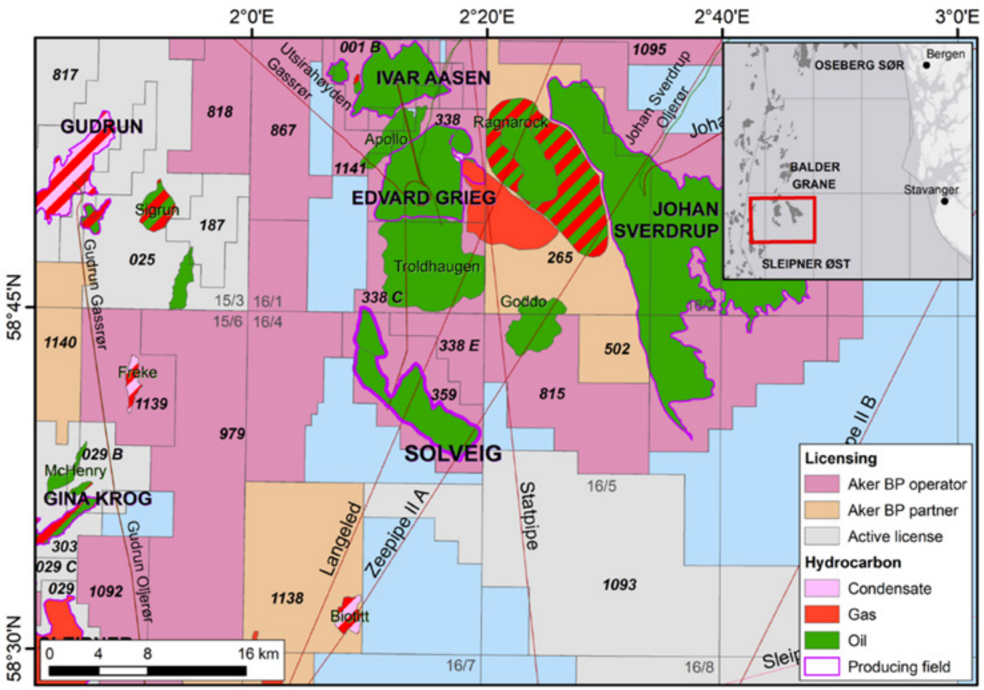
Both the Outer Wedge and the Synrift reservoir varies from coarse-grained alluvial fan conglomerates, sandy desert or alluvial plains and mature aeolian and fluvial systems. Synrift has a somewhat poorer reservoir quality than the Outer Wedge, but both are varying as a function of sediment maturity.

Development

Phase 1 of this development was finished in February 2022 after drilling and completing three oil producers and two water injectors. All the Phase 1 wells are single satellites, which are commingled and tied back to the Edvard Grieg platform. The oil and gas are processed at Edvard Grieg before export. The Edvard Grieg platform is connected to Oseberg Transport System (OTS) through the Edvard Grieg Oil Pipeline (EGOP) and Grane Oil Pipeline (GOP) and to the Scottish Area Gas Evacuation System (SAGE) through the Utsira High Gas Pipeline (UHGP).

Production start-up was during Q3 2021. The Phase 1 development targets the Outer Wedge reservoir unit in Segments B and C, with a test production of the Synrift reservoir in Segment B through one of the development wells, see Fig.3.11. The Phase 2 development is described further under the Development Project section.

Figure 3.10 **Solveig location map**



Status
Solveig came on stream in Q3 2021, producing back to the Edvard Grieg platform. In 2021, the reserves for Solveig were increased to account for the positive drilling results from the development wells in Phase 1, which is also supported by the first years of production.

The drainage strategy on Solveig has been to gain as much production experience as possible to mature the Phase 2 development. Segment B Synrift has therefore been prioritised. Pressure maintenance is the primary injection strategy. The Solveig field has been operated with the aim of maximising production from the Edvard Grieg and Ivar Aasen Hub.

The recoverable volumes on Solveig Phase 1 remain unchanged for 2024 and are classified as "Reserves; On production" (SPE's classification system).

The current PL359 licensees are Aker BP (operator) 65 percent, OMV (Norge) AS 20 percent, Harbour Energy Norge AS 15 percent.

3.1.11 Troldhaugen (PL338C)

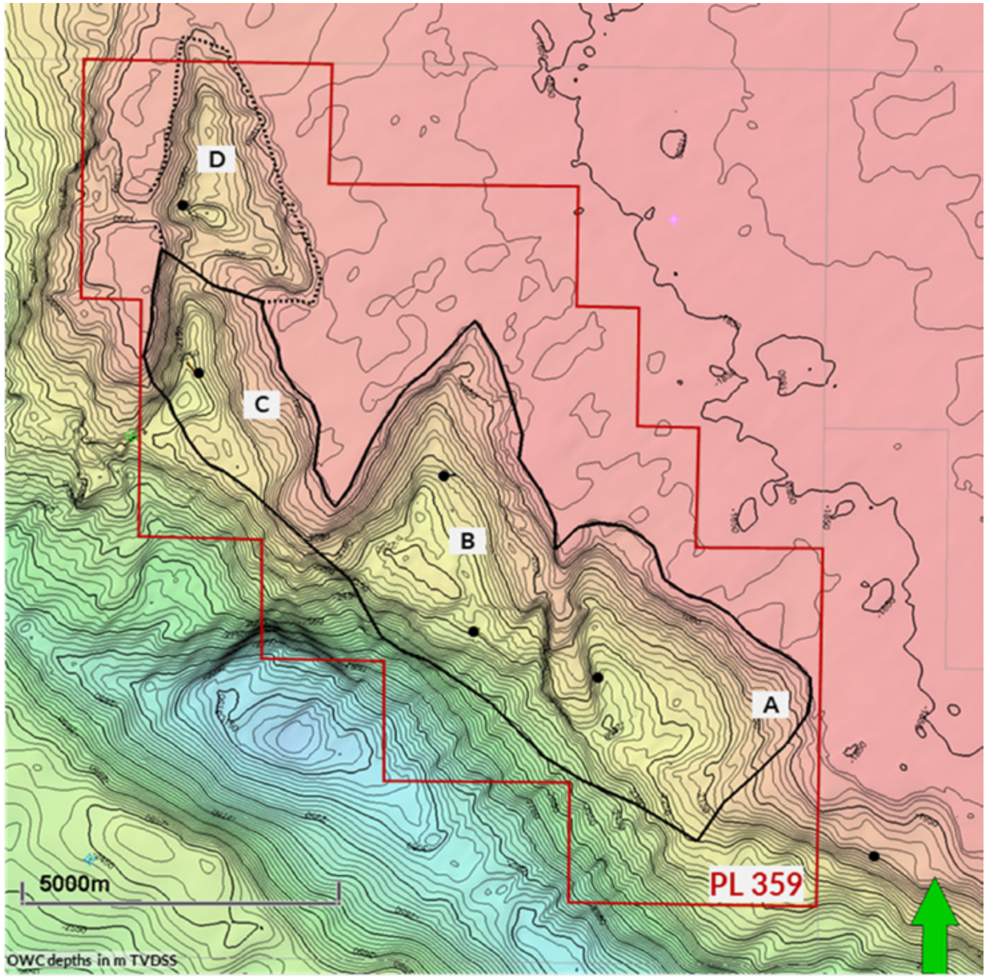
Troldhaugen (previously Rolvsnes) is a field located in the PL338C/PL338E licences on the Utsira High in the Norwegian sector (blocks 16/1 and 16/4) of the North Sea, see Fig. 3.13. Ownership in the licences is aligned with Aker BP ASA holding 80 percent (operator) and OMV (Norge) AS 20 percent. This alignment of ownership allows for development optimisation for the two licences.

Discovery
The first two wells drilled in PL338C, the discovery well 16/1-12 (2009) and the appraisal well 16/1-25 S (2015), proved an oil column of approximately 30 metres. A third well, 16/1-28 ST2 (2018), was drilled horizontally through 2550 metres of weathered and fractured basement. Since August 2021, this well has been used for the ongoing Troldhaugen Extended Well Test (EWT), tied to the Edvard Grieg platform, and has been renamed 16/1-CA-1 H. It was the first dedicated production from weathered basement reservoirs on the Norwegian Continental Shelf.

In licence PL338E, only one well has been drilled, 16/4-5 (2010). At this location, basement was tight. However, significant variability in basement reservoir quality has been observed among the around 30 wells that have penetrated basement in the Utsira High area, even wells that are relatively close to each other. This is also consistent with expected geological variability in weathered basements, suggesting that this well may not be representative for the entire PL338E licence.

Reservoir
The reservoir consists of fractured and weathered basement. The original mineralogy is mainly granite and granodiorite of Ordovician/Silurian age. Utsira High was exposed for tropical weathering during much of the Mesozoic. Weathering takes place by interactions between meteoric water and rocks along the fluid pathways. The degree of weathering depends on several factors such as exposure time, rock mineralogy,

Figure 3.11 **Segment overview Solveig**



fractures, (paleo-)climate and (paleo-)topography. A relatively slow erosion rate is a requirement for subsequent preservation of the weathered zone. This is typically the case in relatively flat areas within a tectonically stable region, like in much of present-day Australia or the African Savannah. Weathered zones can become fully protected against further erosion by being flooded and buried under sediments.

Development

Troldhaugen is a subsea tie-back to Edvard Grieg via the Troldhaugen EWT infrastructure consisting of one production pipeline, umbilical and gas lift.

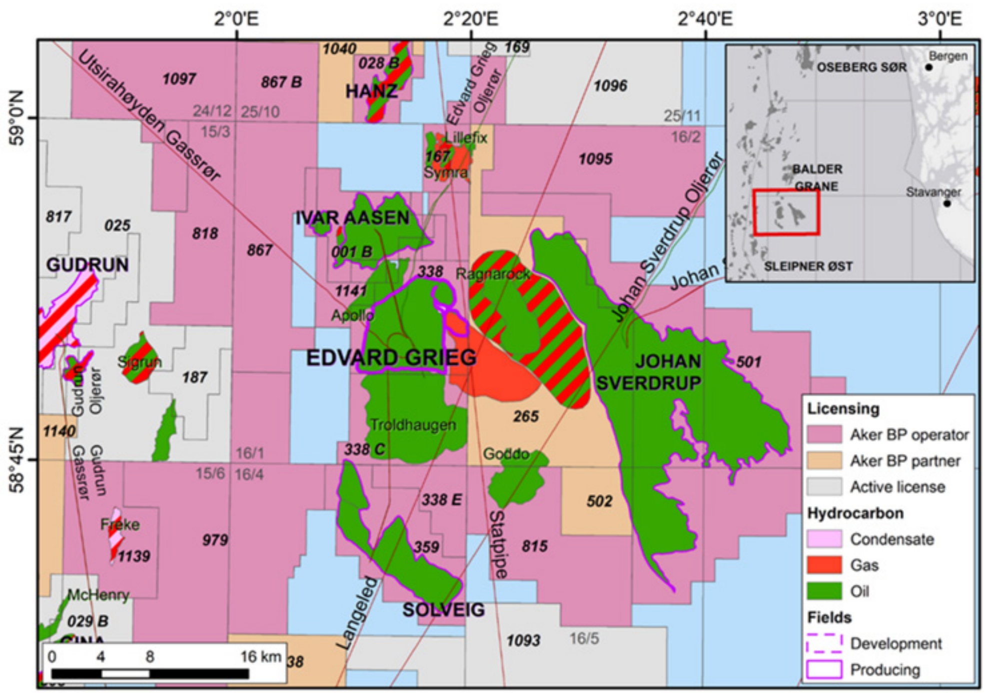
Status

The EWT production started on 7 August 2021. Increasing water cut was observed after a couple of weeks but has since stabilised. The test performance and significant data acquisition has formed the basis for the current understanding of dynamic reservoir performance.

The reserves on Troldhaugen include EWT production only, until the earliest end date for the test production period which is 31 December 2025. These volumes are classified as "Reserves; On production" (SPE's classification system).

Remaining volumes in Troldhaugen are classified as contingent resources, see Chapter 4.

Figure 3.12 **Troldhaugen location map**



3.1.12 Skarv Unit (PL262, PL159, PL212B, PL212)

Skarv/Idun is an oil and gas field located about 35 km southwest of the Norne field in the northern part of the Norwegian Sea in blocks 6507/2, 6507/3, 6507/5 and 6507/6. The water depth in the area is 350-450m. The Skarv unit is a joint development of the Skarv and Idun, Gråsel and Ærfugl fields. Note that the northern part of the Ærfugl discovery, Ærfugl Nord, is not a part of the Skarv Unit, Figure 3.13, but is described here together with Ærfugl.

3.1.13 Skarv

Discovery

Gas and oil were discovered in the Skarv A segment by 6507/5-1 in 1998. The field was later appraised and gas with an oil column was found in the Skarv B and C segments. Dry gas was discovered in Idun 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 23 wells. Distribution between the well types in the Skarv/Idun is: six oil producers, six gas producers and two gas injectors. In addition, there is one oil producer and a commingled injector in Gråsel and seven Ærfugl gas producers. Gråsel and Ærfugl are described in separate sections in this chapter. Idun Tunge has a single gas producer drilled from the Skarv A template.

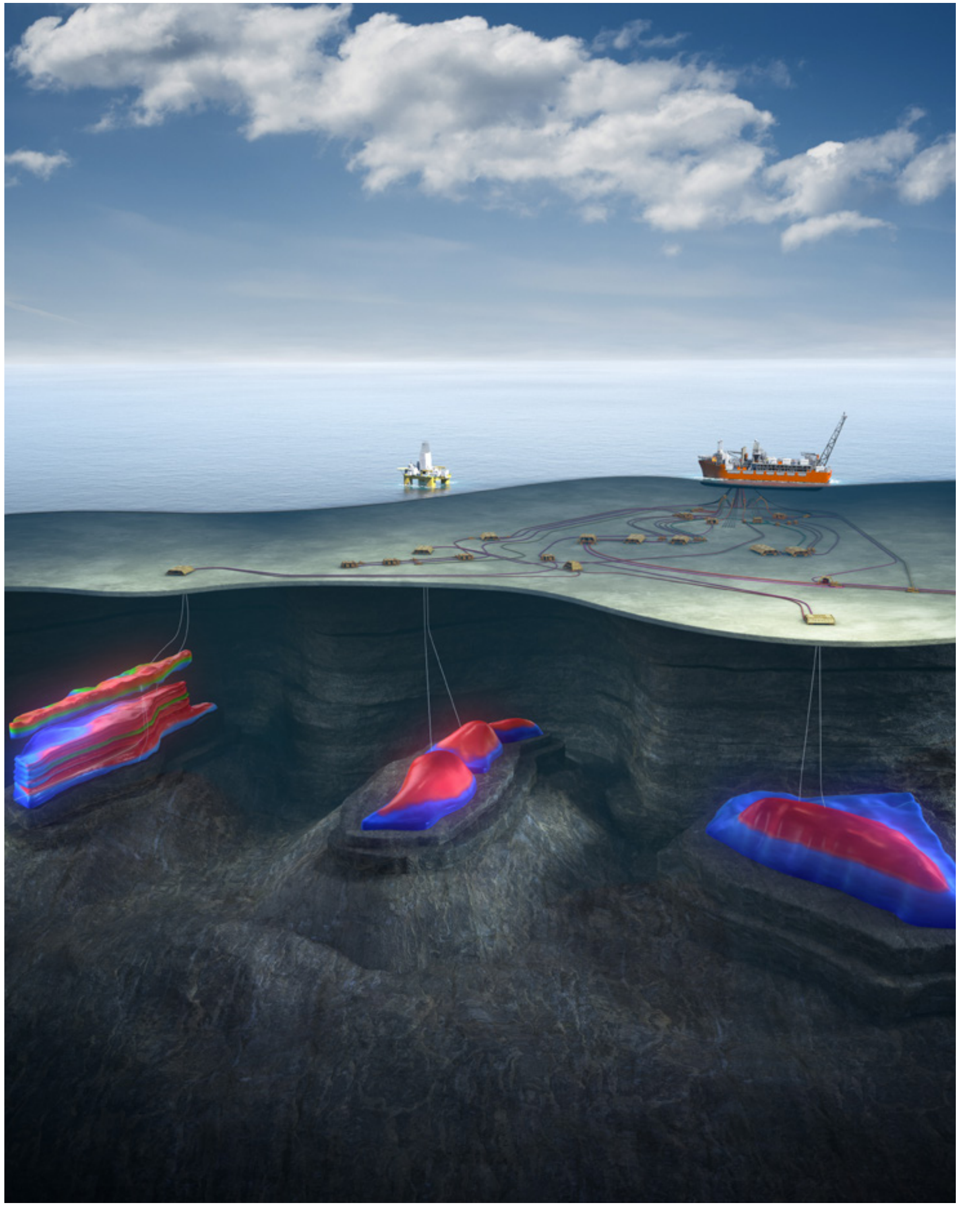
The oil is exported by a shuttle tanker. The gas is exported in an 80-km pipeline connected to the Åsgard Transport System. Capacity in Gassled is secured through the Gassco booking system.

Reservoir

The Skarv structure is defined by three segments, A, B and C, separated by faults. However, production experience indicates that the faults may be leaking. Idun (East and West) is a separate, gas filled structure with no communication to the Skarv A, B, C segments. The segments were initially close to hydrostatic pressure. Each segment constitutes 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.

The 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. Gas blowdown started in the Skarv B and C segments in March 2022. The gas-filled segments are produced by depletion.



Status

Skarv/Idun production started on 31 December 2012. To date, approximately 80 percent of the estimated ultimate oil recovery has been produced and 94 percent of estimated ultimate gas segment recovery. Two gas wells are currently still producing in Garn A. The two Idun wells were shut in due to back pressure from Ærfugl wells but production restarted in June 2024 when the flowline was moved over to the low-pressure separator. All gas wells are on decline.

Gas blowdown started in the B and C segments in March 2022. The two gas injectors were shut-in and the four oil producers produce with increasing GOR. In 2023, the 2 gas injectors were converted to gas producers. The reservoir pressure is falling at 6 bar/month. The two oil wells in the Tilje Formation in the A segment continue to produce with slightly increasing gas rates throughout 2024. A new Tilje oil producer is being drilled with production start planned for 1Q 2025.

There is very little formation water production seen from Skarv.

The recoverable volumes on Skarv and Idun, including Gråsel, Idun Tunge, Ærfugl and Ærfugl Nord, are classified as "Reserves; On production" (SPE's classification system).

Aker BP is the operator and holds 23.835 percent interest in the Skarv Unit. The remaining interest is held by Equinor Energy AS (36.165 percent), Harbour Energy Norge AS (28.0825 percent) and ORLEN Upstream Norway AS (11.9175 percent).

3.1.14 Gråsel

The Skarv discovery well, 6507/5-1, also found oil in Cretaceous sandstones from the Cromer Knoll Group in the Lange Formation, which is the Gråsel discovery.

Reservoir

The Gråsel discovery is situated stratigraphically above the Skarv field. Shallow marine sandstones from the Late Cretaceous, Lange Formation, form the main reservoir. The field exhibits high reservoir porosity and permeability (approx. 1-5 D). The Gråsel field is defined by a combined structural and stratigraphic trap, pinching out to the northeast with dip-closure in all other directions. The reservoir is texturally complex sandstone with thin argillaceous layers, crossbedding and bioturbation.

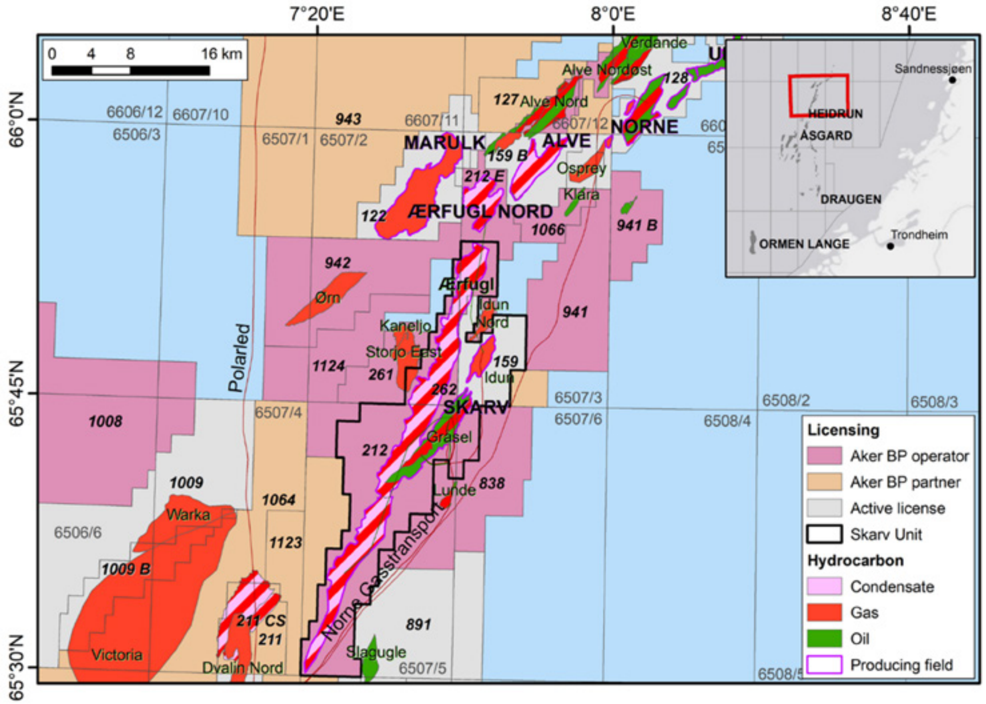
Development

The Gråsel reservoir is developed with one oil producer (B-7 AH) and one gas injector commingled with Skarv Tilje (J-3 H), tied back to the FPSO.

Status

B-7 AH started producing in June 2021 with oil rates around 2000 Sm^3/d. First injection in Gråsel (J-3H) was September 2021 and producer-injector communication was confirmed after 3 months. During 2024, the oil rate has continued to fall as the GOR has increased. The plan is to go to gas blowdown in 2026.

Figure 3.13 **Skarv and Ærfugl location map**



3.1.15 Ærfugl

Ærfugl is a gas condensate field located about 35 km southwest 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 Figure 3.13. Water depth in the area is 350-450 metres and the reservoir depth is about 2800 metres TVD MSL. The field was tested through one producer tied into the Skarv facilities for four 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 in 2012 by well 6507/3-9 S for Ærfugl Nord.

Development

The Ærfugl field is produced through the existing facilities on Skarv and developed with seven highly deviated subsea wells tied into the Skarv FPSO with heated flowlines. In addition to the original A-1H test producer, three wells were drilled on Ærfugl South and came on stream in November 2020. A second drilling phase included three wells towards the north. The first well was drilled from the Idun template and came on stream in 2020, while the two remaining wells came onstream end 2021. One of these wells, G-1H, is located in the Ærfugl Nord licence.

Status

The A-1H test producer in Ærfugl started gas production in February 2013 and continues to produce. Early production from this well provided excellent data which helped to significantly de-risk the Ærfugl development. The Idun template well, D-4H, experienced water breakthrough earlier than expected and did not start up after a shut-down in September 2023. A sidetracked is currently being evaluated. Two of the Southern wells, L-1H and M-1H, have also experienced water breakthrough but had successful water shut-off operations. The Ærfugl Nord (G-1AH) experienced water breakthrough in May 2023. A new infill well was drilled and put on stream in October 2024 between A-1H and D-4H.

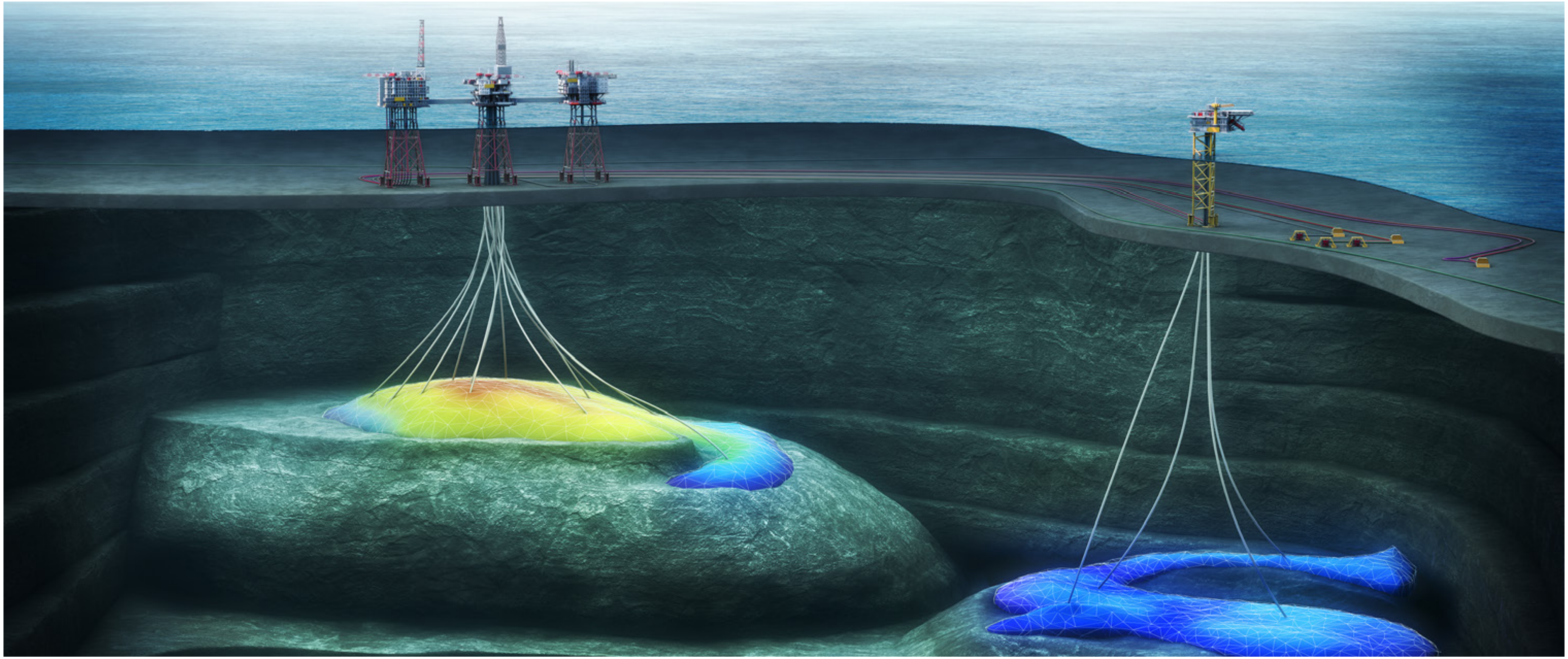
The Ærfugl field is in the Skarv Unit. Aker BP holds a 23.835 percent share in the Unit. The northern extension, Ærfugl Nord is in licence PL212E, where Aker BP holds a share of 30 percent.

3.1.16 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, Figure 3.14. The water depth in the area is about 70 metres and the reservoir depth is about 3500 metres TVD MSL.

Discovery

Ula was discovered in 1976 by well 7/12-2, which encountered a substantial Late Jurassic reservoir in the Ula Formation. The well was drilled to a depth that included a Triassic hydrocarbon-bearing sequence comprising low-quality sands interbedded with shales. Core analysis and log interpretation identified an Ula Formation sandstone reservoir with a net thickness of 128 metres, porosities ranging from 14 percent to



28 percent, permeabilities varying from a few millidarcies (mD) to over 2 darcies (D), and water saturations between 5 percent and over 50 percent. The Ula Formation was oil-bearing from top to base, with the oil-down-to point recorded at 3532 metres.

Reservoir

The main reservoir is at a depth of 3345 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.

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 Oda, Tambar and Blane. The oil is transported by pipeline via Ekofisk to Teesside in the UK. All gas is reinjected into the reservoir to increase oil recovery.

Oil was initially recovered by pressure depletion, but after a period, water injection was implemented to improve recovery. Water alternating gas (WAG) injection started in 1998. The WAG program has been extended with gas from Tambar (2001), Blane (2007), Oda (2019) and Oselvar (2012, now ceased). Gas lift is used in the shallowest reservoir interval.

Status

49 wells have been drilled on Ula since start-up, of which eight wells are currently producing and four are injecting.

The planned Cessation of production (CoP) of the Ula field is 2028. The calculated economic cut-off on the 2P/P50 production profiles is end 2027. The Ula Management Committee has decided to plan for continued production from Ula until 2028. This will allow production from the tie-in fields.

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

Aker BP is the operator and holds an 80 percent interest in the Ula field. The remaining 20 percent share is held by DNO Norge AS.

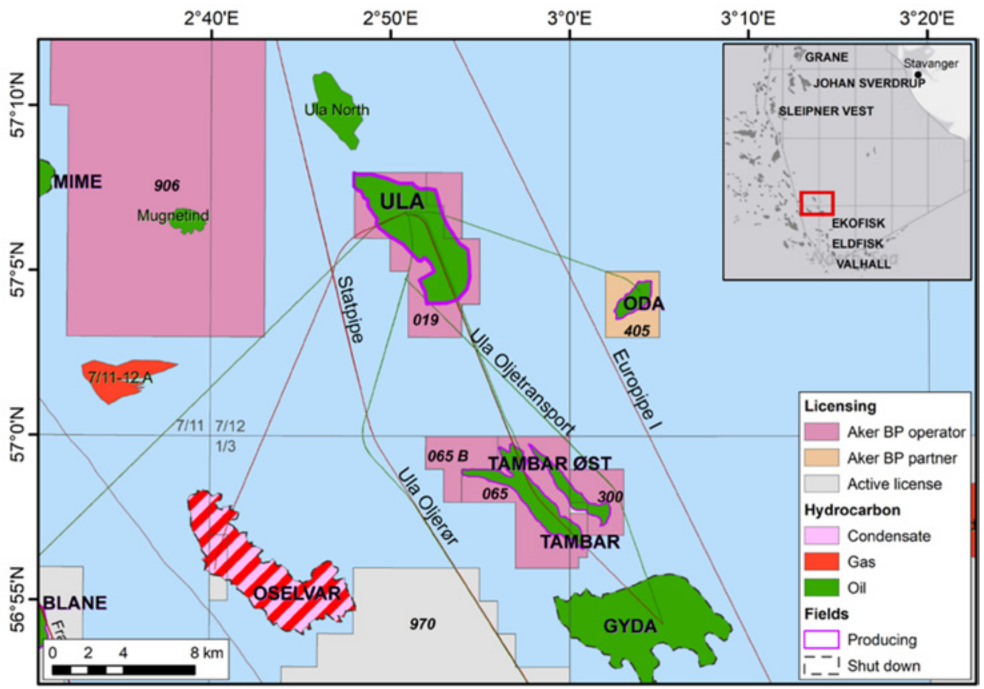
3.1.17 Tambar (PL065)

Tambar is an oil field about 16 kilometres southeast of the Ula field in the southern part of the Norwegian sector of the North Sea, Figure 3.15. The water depth in the area is 68 metres.

Discovery

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

Figure 3.14 **Ula location map**



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 4100-4200 metres and the reservoir characteristics are generally very good. The field is produced by pressure depletion, with expansion and aquifer support as the main reservoir drive mechanisms.

Development

The field was developed with a remotely controlled wellhead facility without processing equipment. The produced fluids are 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 six producers have been drilled on Tambar since start-up, of which three wells are currently producing. Two of the Tambar producers have been producing in a cyclic manner due to low reservoir pressure/limited pressure support. A work-over of an additional producer, shut-in since 2017, was approved early in 2024. The work is scheduled for the first half of 2025.

The planned Tambar field Cessation of production (CoP) is 2028, but current economic cut-off is in end 2027.

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

Aker BP is operator and holds 55 percent interest in the Tambar field. The remaining 45 percent share is held by DNO Norge AS.

3.1.18 Tambar East (PL065, PL300, PL019B)

Tambar East (Tambar Øst) is a minor oil field located east of Tambar, see Figure 3.15.

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

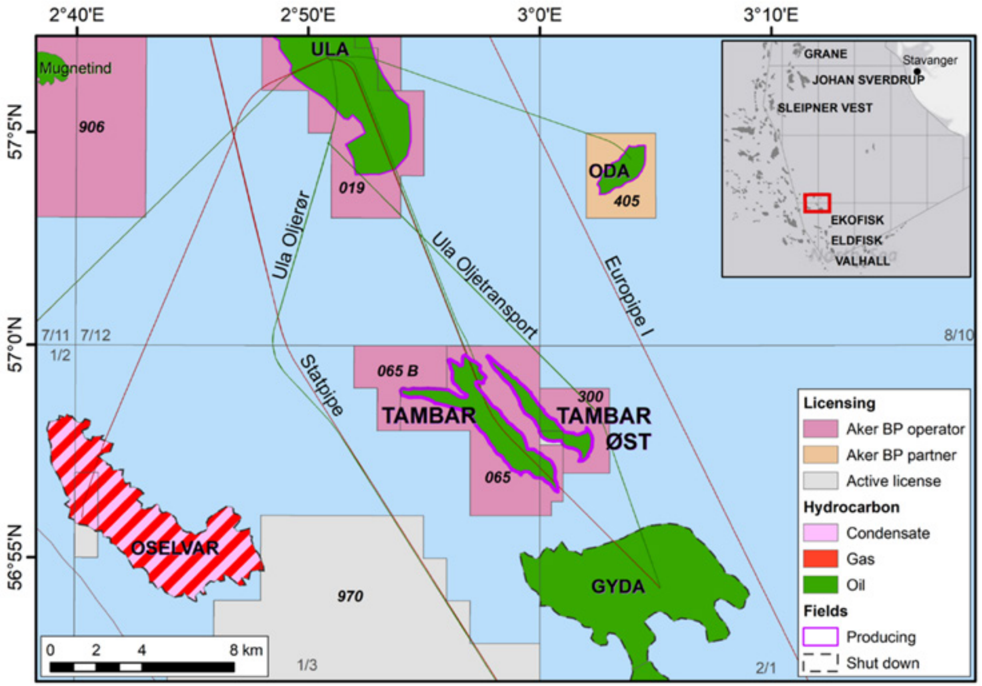
Reservoir
The reservoir consists of Late Jurassic sandstones, deposited in a shallow marine environment. The reservoir lies at a depth of 4050-4200 meters and the quality varies but is generally poorer than in the Tambar main field. The field is produced by pressure depletion. The reservoir is believed 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 Figure 3.14. The produced fluids are 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
The so far only development well, the K-5 AT2, has been shut in since the beginning of 2024. A sidetrack of it, the 1/3-K-5 B, was approved by the license in December 2023. The purpose of the slanted sidetrack trajectory is 1) to target the previously undrained A-sand for production and 2) to continue production from the C-sand at a different location Startup is expected in the first half of 2025.

Figure 3.15 **Tambar and Tambar East location map**



The planned Tambar East field CoP is 2028, but current economic cut-off is at the end of 2027.

Aker BP is the operator and holds 46.2 percent interest in the Tambar East Unit. The remaining shares are held by DNO Norge AS (37.8 percent), Repsol Norge AS (9.76 percent), and ORLEN Upstream Norway AS (6.24 percent).

3.1.19 Valhall (PL006B, PL033B)

Valhall is an oil field in the southern part of the Norwegian sector of the North Sea in PL006B and PL033B (unitised into the Valhall Unit) in blocks 2/8 and 2/11, Figure 3.15. The water depth is about 70 metres.

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 2400 metres. The Tor Formation chalk is fine-grained and soft; with high porosity (up to 50 percent). Matrix permeability is in the 1-10 mD range. There are areas with natural fractures with high permeability conduits. The Hod Formation porosity is 30 percent-38 percent with permeability 0.1-1mD.

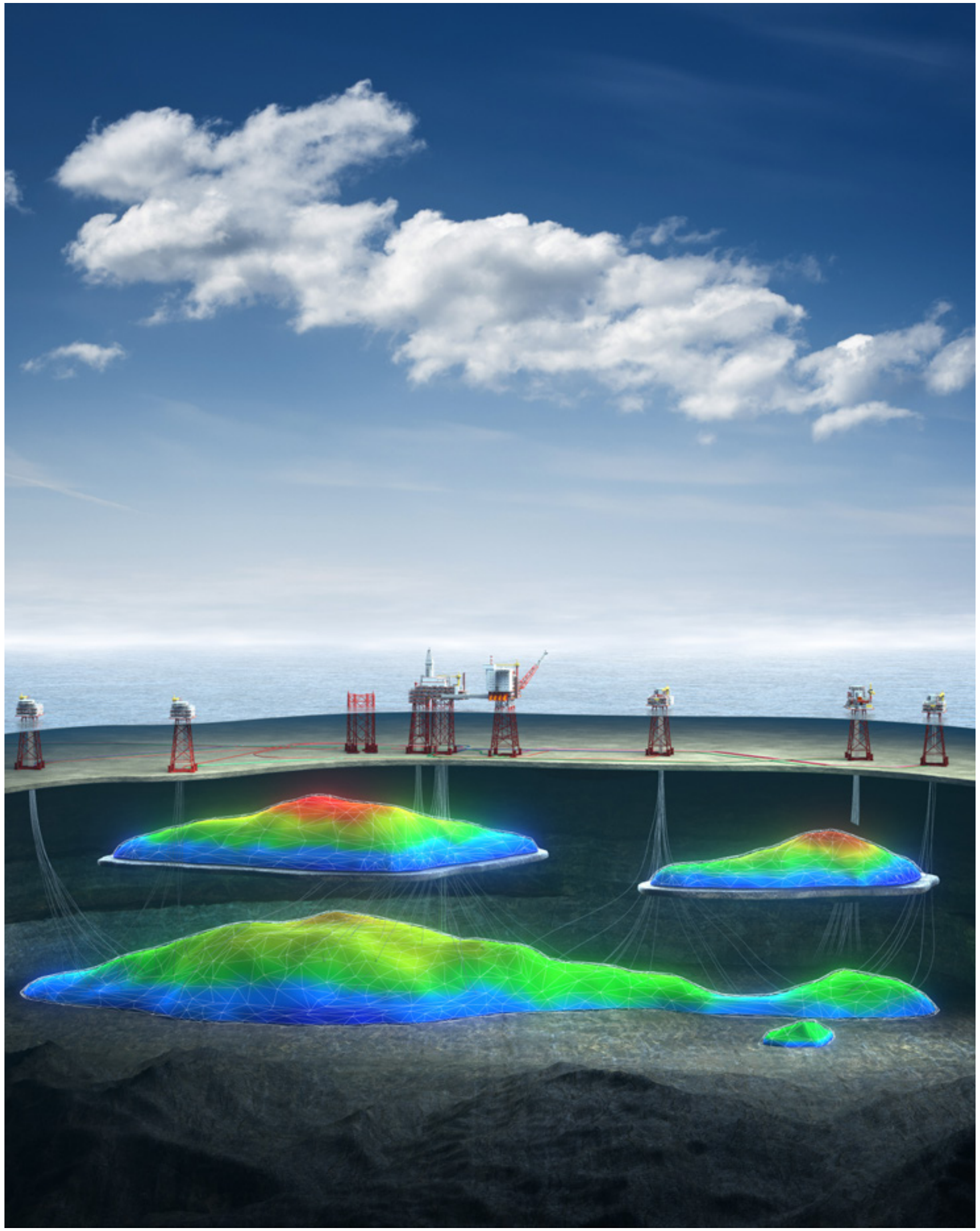
The Valhall field is subdivided into nine reservoir regions: North Flank, Northern Basin, East Flank, West Flank, South Flank, Central Crest, Southern Crest, Upper Hod and Lower Hod. The seven first regions are located within the Tor formation. Upper and Lower Hod regions is poorer chalk formation below the Tor 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 (QP, DP & PCP). 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 next to WP. Two satellite wellhead platforms (SF & NF) were installed in 2003 with 16 slots each, drilling targets to the South and North Flanks of the field. In 2013, a new integrated Production and Hotel Platform (PH), bridge linked to the IP Platform was put to use. A satellite wellhead platform (WF) with 12 well slots was sanctioned in 2017, drilling targets to the West Flank. The original PCP, QP and DP platforms have been decommissioned.

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



Status
Valhall currently has 53 active producers and nine active injectors.

During 2023, Valhall drilled one new well from North Flank (N-11 AT2) that started producing 9 January 2024. The recoverable volumes for Valhall Base are classified as “Reserves; On production”.

The Valhall PWP (Production and Wellhead Platform) project delivered a PDO in 2022. Valhall PWP consists of a joint development for the Valhall and Fenris fields (Fenris development is described in Chapter 3.2). Valhall PWP will be bridge-linked to Valhall PH and will include the following functions:

- 24 new wells slots for Valhall drilling.
- Riser for gas export to Emden. This function is currently located on Valhall WP. The plan is to decommission Valhall WP by the end of 2028.
- Riser for gas lift pipelines to satellite platforms (currently located on Valhall WP).
- Upgrade of the Valhall produced water treatment facility (currently located on Valhall PH).
- Facilities to process production from Fenris.

The Valhall PWP PDO describes a plan to use 15 of the 24 well slots, leaving nine slots available for future developments. 14 new development wells and one waste injector. The plan is to install the PWP jacket and well bay in 2025 and the topside module in 2026. The development will have a pre-drill campaign (7 wells) starting in 2025 and the main drilling campaign in 2026 (8 wells). The final commissioning and first oil from Valhall PWP and Fenris is planned in 2027. The 14 Valhall development wells will target both the Tor and Hod Formations, with expansion of the waterflood in both formations. In 2023 the PDO was approved by government in 2023. The recoverable volumes for Valhall PWP have been classified as “Reserves; Approved for development”.

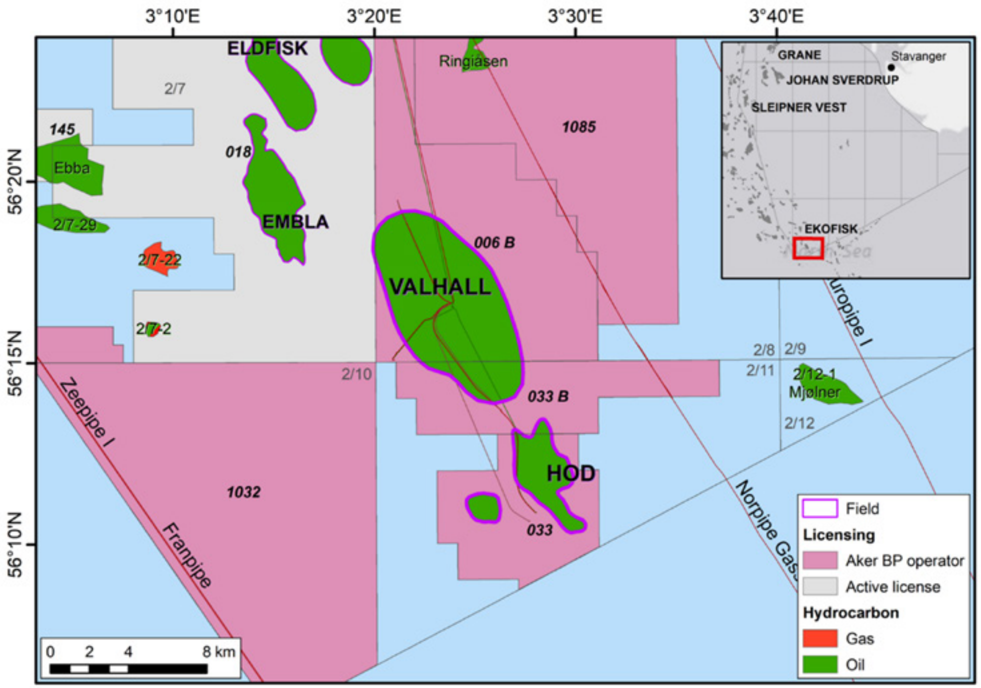
The 2P/P50 production profile indicates an economic cut-off (Cessation of production, CoP) in 2049.

Aker BP holds 90 percent interest in the Valhall field, with Pandion Energy AS holding the remaining 10 percent.

3.1.20 Hod (PL033)
Hod is an oil field 13 km south of the Valhall field in the southern part of the Norwegian sector in the North Sea (PL033 in block 2/11), see Figure 3.16. The water depth is approximately 70 metres and the reservoir depth is about 2700 metres TVD MSL.

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

Figure 3.16 **Valhall and Hod location map**



Reservoir
The reservoir lies in chalk in the lower Palaeocene Ekofisk Formation, and the Upper Cretaceous Tor and Hod formations. The field consists of three structures: Hod West, Hod East and Hod Saddle.

The field has been produced by pressure depletion. Gas lift has been used in some wells to increase production and lift performance.

Development
The field was initially developed with an unmanned production wellhead platform (Hod A) which was remotely controlled from Valhall. Since 2012, there has been no production from Hod A. The Hod Saddle reservoir is currently produced through three wells drilled from Valhall Flank South. In 2021, a new

unmanned wellhead platform (Hod B) was installed with 12 well slots. Six new wells were drilled in 2021 and 2022, and production from all these wells started in 2022. The initial Hod facility (Hod A) awaits decommissioning and disposal.

Transport of oil and NGL from Hod and 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
Hod field is currently produced from six Hod B wells and three wells drilled from the Valhall South Flank platform that extends into the Hod license. The equity split between the Valhall and Hod license is based on 'length of well' in respective licenses. The wells at the Hod A facility are awaiting final P&A.

Hod field Cessation of production (CoP) is estimated to be 2049, same as for the Valhall field.

The recoverable volumes for Hod Base are classified as "Reserves; On production".

Aker BP has a 90 percent interest in the Hod field, with Pandion Energy AS holding the remaining 10 percent.

Figure 3.18 **Johan Sverdrup field centre**

Foto: Lizette Bertelsen & Jonny Engelsvoll/Equinor

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

Johan Sverdrup is a major oil field extending over four licences (PL265, PL501, PL502 and PL501B), and the 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 160 km west of Stavanger in blocks 16/2, 16/3 and 16/5; see Figure 3.17. The water depth in the area is 110-120 metres and the reservoir depth is about 1900 metres TVD MSL.

Discovery

The discovery well 16/2-6 was drilled in 2010 on the Avaldsnes High. The well proved oil in Jurassic and pre-Jurassic sandstones. A large number of wells have been drilled since then to appraise the discovery.

Reservoir

The reservoir consists of late to middle-early Jurassic sediments in Draupne sandstone and in the older Statfjord and Vestland Groups. The reservoirs are characterised by excellent reservoir properties. The apex of the field is located at approximately 1840 metres TVD MSL and the free water levels (FWL) encountered are in the range of 1922 – 1934 metres TVD MSL. Top reservoir is generally regular and gently dipping towards the east and the south, whereas the base is an unconformity and has an irregular character. 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 a large part of the field having thin reservoir below seismic resolution.

The reservoir fluid is highly undersaturated oil with a low GOR ranging between 40 and 80 Sm^3/Sm^3 and with a viscosity of approximately 2 cP.

Generally, the Phase 1 field development is based on producers located in the central/western thicker parts of the field, with water injection located down dip in the water zone in the eastern and southern parts of the field.

Development

The PDO for Phase 1 was approved by the authorities in August 2015. The Phase 1 development plan includes a field centre with four platforms: a processing platform (P1), a drilling platform (DP), a riser and export platform (RP) and a living quarters and utilities platform (LQ), see Figure 3.18. The platforms are installed on steel jackets linked by bridges.

Phase 1 also includes 18 oil production and 16 water injection wells and three subsea water injection templates. Production from Phase 1 commenced on 5 October 2019.

Phase 2 (the full field development) develops the reserves in the fringe areas of the field as well as enables acceleration of production from the Phase 1 area. The PDO for Phase 2 was submitted in August 2018 and approved by the authorities in the spring of 2019. Production start was on 15 December 2022. The Phase 2 development includes an additional processing platform (P2) located next to the riser platform at the field centre, Figure 3.18. The fringe areas are developed with subsea templates tied back to the riser platform. The wells are a mixture of subsea wells and additional wells drilled from the central drilling platform.

Phase 1 and Phase 2 PDOs include 62 oil production and water injection wells on Johan Sverdrup. Before start-up of Phase 2, the field was producing at a plateau of 535,000 bbl/d oil. After Phase 2 start-up, the oil production plateau production was expected to be at least 720,000 bbl/d. In May 2023 it was proven to be 755,000 bbl/d.

The oil and gas are transported to shore via dedicated pipelines. The oil is transported to the Mongstad terminal, and the gas is transported via the Statpipe system to Kårstø for processing and onward transportation.

Status

Production from Phase 1 started on 5 October 2019. After a very successful ramp-up, the field has produced with high regularity. The oil production capacity was increased to a production level of 535,000 bbl/d (approximately 180,000 boe/d net to Aker BP) from 19 producers, supported by 15 water injection wells (December 2022).

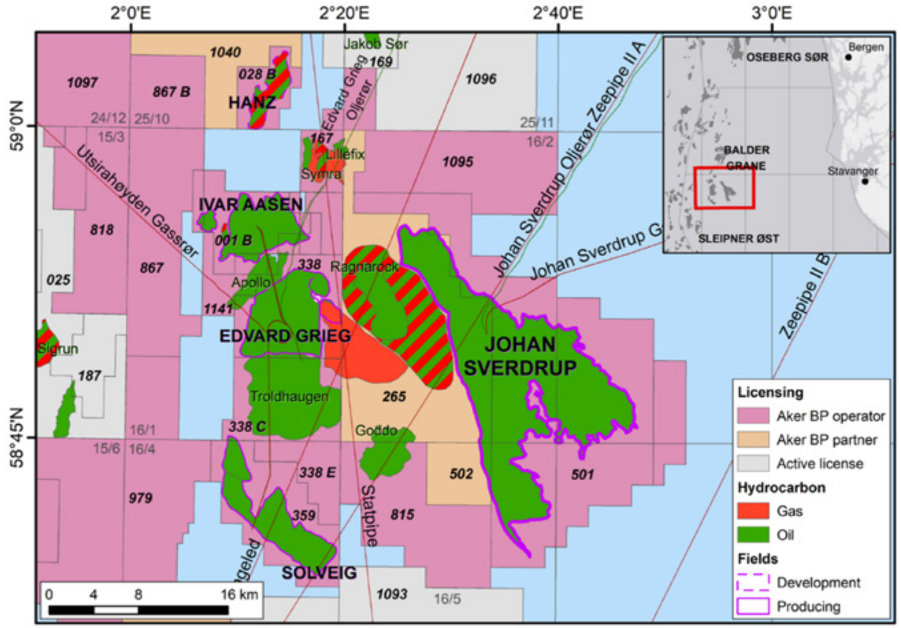
The PDO for Phase 2 was submitted in August 2018 and approved in early 2019. Production from Phase 2 started on 15 December 2022. The production level was ramped up to the expected new plateau rate of 720,000 bbl/d in the first quarter of 2023 and was further increased to 755,000 bbl/d in May 2023. This maximum oil capacity has been maintained throughout 2024, but the field is expected to go on decline during 2025.

Aker BP has included reserves assuming a full field development of the field in the reserve base (both Phase 1 and Phase 2), including volumes from the WAG-project (which has been approved by the licence).

The volumes related to the Phase 1 and Phase 2 development are classified as "Reserves; On production", whereas the volumes related to WAG are classified as "Reserves; Approved" (SPE's classification system).

Several IOR/EOR techniques have been identified which may increase the reserves on Johan Sverdrup. The most promising is infill drilling. In 2022, two infill well targets were approved by the partnership, adding to the reserves base. An additional three infill wells were approved in 2023. Four of the five infill wells were drilled and put on production in 2023 and the final well was put on production in 2024. The volumes related to these five infill wells are classified as "Reserves: On production" (SPE's classification system).

Figure 3.17 **Johan Sverdrup location map**



In 2024 a 4-well retrofit multi-lateral (RMLT) campaign was approved and will be executed in 2025. The volumes related to these four RMLT wells are classified as "Reserves: Approved" (SPE's classification system).

Estimated economic cut-off (Cessation of production, CoP) for the Johan Sverdrup field is in the 2P-case year-end 2055.

The unit agreement gives Aker BP a 31.5733 percent share of the field. The remaining shares are held by Equinor Energy AS (42.6267 percent, operator), Petoro AS (17.3600 percent) and TotalEnergies EP Norge AS (8.4400 percent).

3.1.22 Oda (PL405)

The Oda field is located ~8 km east of the Ula field in Block 8/10, PL405, on the eastern side of the Central Graben in the Norwegian North Sea (Figure 3.18). The water depth is about 66 metres. The crest of the structure is estimated at approx. 2300 metres TVD MSL. The PDO was approved by the authorities in May 2017. Production commenced in March 2019.

Discovery

The discovery well, 8/10-4 S, was drilled in 2011 in the northwestern part of a salt-induced structure. The well proved an oil-down-to situation in the Ula Fm. Based on pressure measurement, OWC is estimated to be at 2985 metres TVD MSL from sidetrack wells 8/10-4 A T2. The east and southwest segments of the structure were drilled dry in 2014.

Reservoir

The Oda reservoir consists of the Upper Jurassic Ula Formation; a sandstone reservoir with high-quality properties, on the western flank of the steeply dipping salt diapir. The oil column is about 485 metres of high-quality, light crude oil. At reservoir datum (2917.5 m TVDss) initial pressure was 409 bar and temperature 125 degrees C.

Development

The development concept is a subsea tie-in to the Aker BP-operated Ula Platform with re-usage of the Oselvar facility and separator at Ula. The Oda reservoir is drained by two producers supported by one water injection well. All the wells have been drilled from an integrated subsea template.

Status

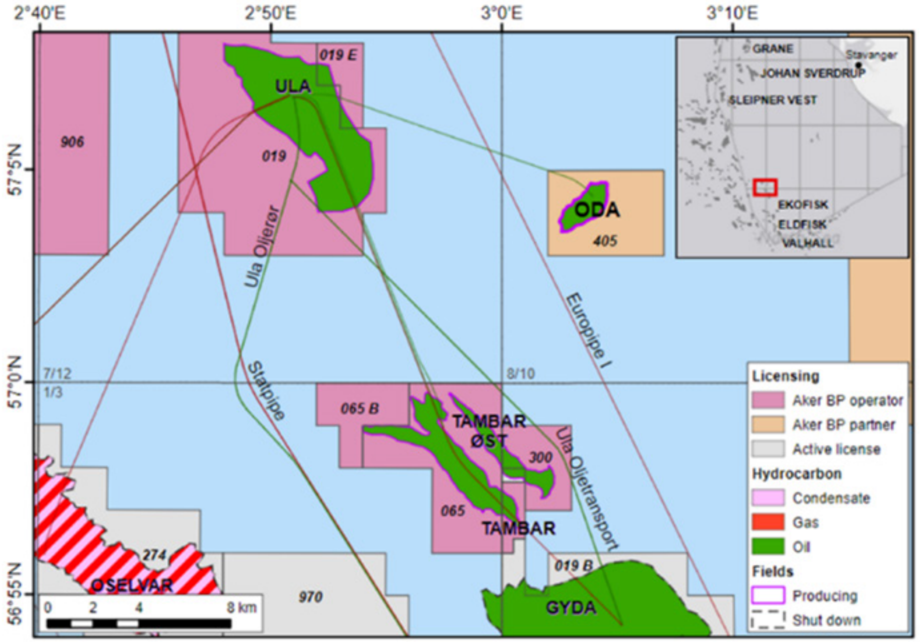
Oda production started in March 2019, five months ahead of plan. The field was produced without pressure support during the first ~7 months due to damage in the water injection pipeline, and technical problems during water injection start up, October 2019. With pressure support, the wells delivered the planned 35mboepd with B-1 H as the main producer. B-3 AH did not deliver as expected, likely a consequence of reduced reservoir thickness and reservoir properties because the well was drilled into a fault.

During 2022, a sidetrack to the well B-1 H was decided and successfully drilled. The sidetrack is placed up dip of the donor well B-1 H and started production in May 2022. The well has been produced with a higher rate and a more slowly water cut development than prognosed in the DG3 estimate for the well.

Oda recoverable volumes are classified as “Reserves; On production” (SPE’s classification system).

Estimated economic cut-off (Cessation of production, CoP) for the Oda field is in the 2P-case year-end 2026.

Figure 3.19 **Oda location map**



Aker BP holds 15 percent interest in Oda. The remaining shares are held by Sval Energi AS (70 percent, operator) and DNO Norge AS (15 percent).

3.1.23 PL048D Enoch Unit

The Enoch field is located in central North Sea on the border of the British sector, 10 km NW of the Gina Krog field. The Norwegian part of the field is in PL048D, block 15/3, where Aker BP holds a 10 percent share. The UK part in block 16/13a P.219. Aker BP holds a 2 percent share of the Enoch Unit.

The field is developed with one oil producer and subsea tie-back to Brae A. First oil 2016 and expected Cessation of production (CoP) is expected mid-2026.

Enoch recoverable volumes are classified as “Reserves; On production” (SPE’s classification system).

3.2 DEVELOPMENT PROJECTS

3.2.1 Skarv Satellite Project (SSP)

The Skarv satellite project consists of the development of the Ørn, Alve Nord and Idun Nord fields, tied back to the Skarv FPSO, see Figure 3.20.

3.2.2 Ørn

Discovery

Ørn is a gas/condensate discovery made in 2019 with well 6507/2-5 S, located 17 km northwest of the Skarv field.

Reservoir

The Ørn reservoir consists of moderate-quality sandstones from the Middle Jurassic Garn Formation. It is characterised by a significant overpressure, with a reservoir pressure of 667 bar.

Development

Ørn will be developed by depletion from two horizontal production wells drilled from a new four-slot subsea template. The template will be connected to a new central manifold which is connected to the Skarv FPSO via a new riser. Ørn will utilise spare processing capacity at the Skarv FPSO.

Status

The PDO was submitted in December 2022 and approved in 2023. The planned start of production is 2027.

The recoverable volumes on Ørn are classified as "Reserves; Approved for development" (SPE's classification system).

Aker BP holds 30 percent in Ørn. The remaining shares are held by ORLEN Upstream Norway AS 40 percent and Equinor Energy AS 30 percent.

3.2.3 Alve Nord

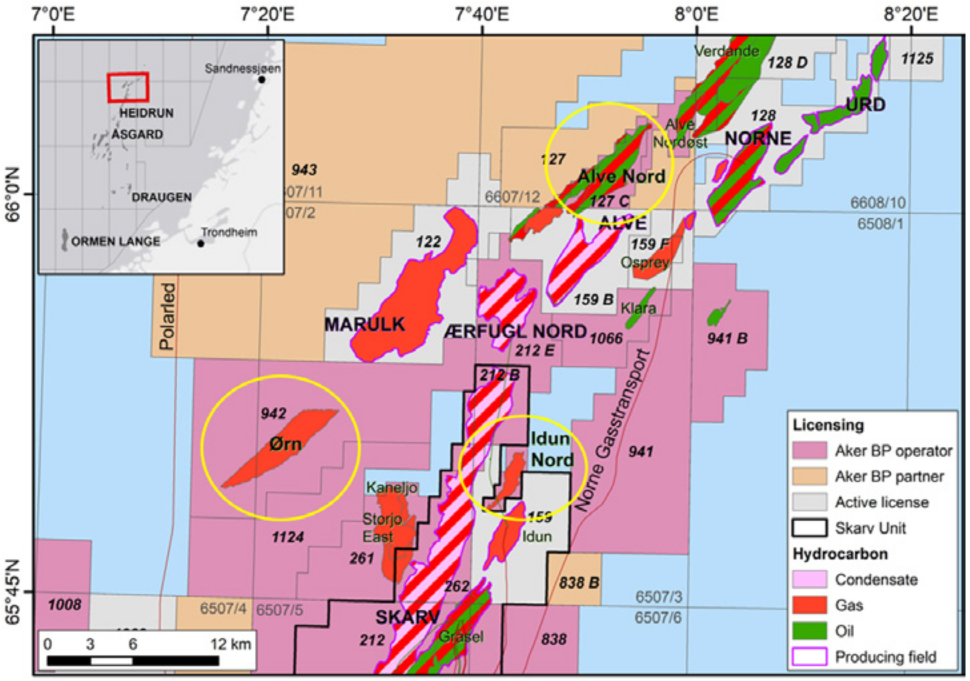
Discovery

Alve Nord was discovered by well 6607/12-2 S drilled in 2011. Alve Nord is located north of Skarv. It is made up of two main reservoir intervals: The sand-rich gravity flows of the Cretaceous Lange Formation and shallow to marginal marine deposits in the Jurassic.

Reservoir

The reservoir quality in the Jurassic is poor to moderate. The Cretaceous Lange interval reservoir quality is moderate to good. The main target is gas.

Figure 3.20 **Skarv satellites location map**



Development

Alve Nord will be drained by depletion by two production wells, one horizontal producer in the Cretaceous and one high-angle well in the Jurassic, drilled from a new four-slot subsea template. The template will be connected to a new central manifold which is connected to the Skarv FPSO via a new riser.

Status

The PDO was submitted to Norwegian authorities in December 2022 and approved in 2023. The planned start of production is 2027.

The recoverable volumes on Alve Nord are classified as "Reserves; Approved for development "(SPE's classification system).

Aker BP holds 68.0825 percent in Alve Nord. The remaining shares are held by ORLEN Upstream Norway AS 11.9175 percent and Harbour Energy Norge AS 20 percent.

3.2.4 Idun Nord

Discovery

Idun Nord was discovered by well 6507/3-7 drilled in 2009. Idun Nord is located just north of the Idun reservoir and the Skarv field. It found gas/condensate in the Garn Formation from the Middle Jurassic.

Reservoir

The reservoir quality in the Jurassic Garn Formation is very good. The reservoir consists of 2 main segments, only one segment is proven and reported as reserves. The reservoir is over-pressured with 473 bar pressure at 3523 metres TVD MSL.

Development

Idun Nord will be drained by depletion and some aquifer support by two production wells drilled from a new four-slot subsea template. A low-angle production well will be drilled into each segment. The template will be connected to a new central manifold which is connected to the Skarv FPSO via a new riser.

Status

The PDO was submitted to Norwegian authorities in December 2022 and approved in 2023. The planned start of production is 2027.

The recoverable volumes on Idun Nord are classified as "Reserves; Approved for development" (SPE's classification system).

Aker BP holds 23.835 percent in Idun Nord. The remaining shares are held by Equinor Energy AS 36.165 percent, Harbour Energy Norge AS 28.0825 percent, and ORLEN Upstream Norway AS 11.9175 percent.

3.2.5 Fenris

The plan is to develop the Fenris reservoir from a new eight-slot unmanned platform through new process facilities located at Valhall PWP (Production and Wellhead Platform).

The Valhall PWP development at the Valhall field is described in Chapter 3.1.21.

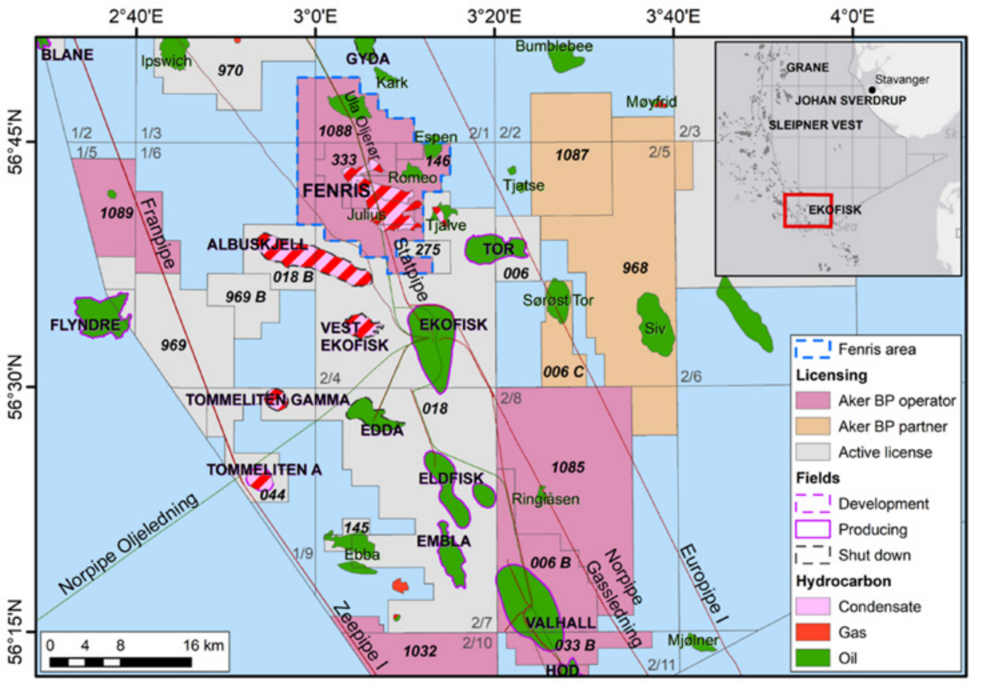
Discovery

The Fenris gas condensate discovery was made in 1989 by well 2/4-14 in the Farsund Formation, and further appraised by wells 2/4-18, 2/4-21, 2/4-21 A and 2/4-23 S. The Ula Formation accumulation was discovered in 2015 by well 2/4-23.

Reservoir

Fenris is a gas-condensate field comprising two Upper Jurassic reservoirs located at approximately 5000 metres depth. The depositional environment is turbidites for the Farsund Formation, and shallow marine sandstones for the Ula Formation. The field is associated with high pressure (950-1050 bar) and high temperature (165-185°C). Well 2/4-14 experienced an underground blowout lasting for 7 to 11 months.

Figure 3.21 **Fenris location map**



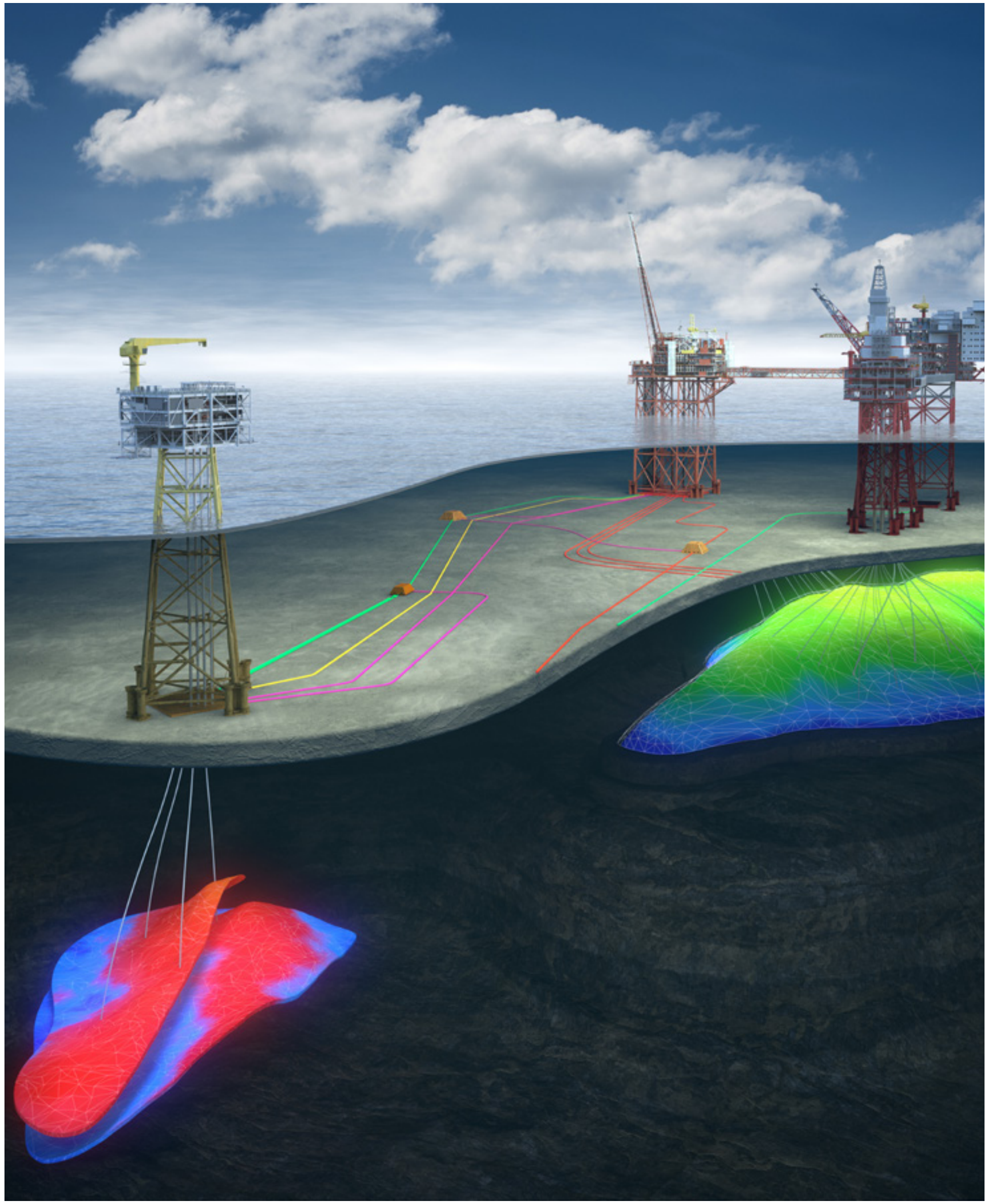
Subsequent wells 2/4-21 (2012) and 2/4-23 S (2015) encountered a reservoir that had been depleted by the 2/4-14 blowout, confirming lateral communication within the Farsund Formation. In the Ula Formation, a mini-DST was acquired in well 2/4-23 S proving flow.

Development

Fenris is being developed with an eight-slot unmanned installation, connected to Valhall via a 50-km pipeline, where gas and condensate will be processed for export. The drainage strategy for Fenris is depletion, with two vertical wells planned in each formation. The first well (Farsund formation production well 2/4-FE-3) was drilled and completed in 2024. The second well (Farsund formation production well 2/4-FE-2) was ongoing at the end of 2024. The two Ula formation wells will be drilled in 2025. Production start is planned in the second half of 2027.

Status
The PDO for Fenris was approved in June 2023. The recoverable volumes on Fenris are classified as “Reserves; Approved for development” (SPE’s classification system).

Aker BP is the operator and holds a 77.8 percent interest in Fenris, with the 22.2 percent held by ORLEN Upstream Norway AS.



3.2.6 Yggdrasil

The Yggdrasil area comprises ten discoveries over a 60-kilometre trend, situated south of Oseberg and northeast of Alvheim, see Figure 3.23. The area includes the Hugin fields (formerly known as the NOA fields), the Fulla field, and the Munin fields (formerly known as Krafla). The Hugin fields encompass the Frøy field, the Frigg Gamma Delta field, the Langfjellet field, and the Rind field. The PDOs/POI were submitted on 16 December 2022.

Aker BP is the operator for the entire area, except for the oil and gas export pipelines, which are operated by Equinor Energy AS. The development of the Yggdrasil area consists of a PDQ platform, Hugin A, located centrally on the Frigg Gamma Delta field, a NUI wellhead platform, Hugin B, on Frøy and an unmanned processing platform, Munin, on the Krafla field. There are also nine subsea templates in total. Oil will be exported via a new pipeline to the Grane Oil Pipeline and further to the Oseberg Transportation System (OTS). Gas will be transported via a new gas export pipeline, with entries from both Hugin A and Munin, to the Statpipe Area A. Power will be supplied from shore via a cable from Samnanger, with a compensation station located on Fitjar.

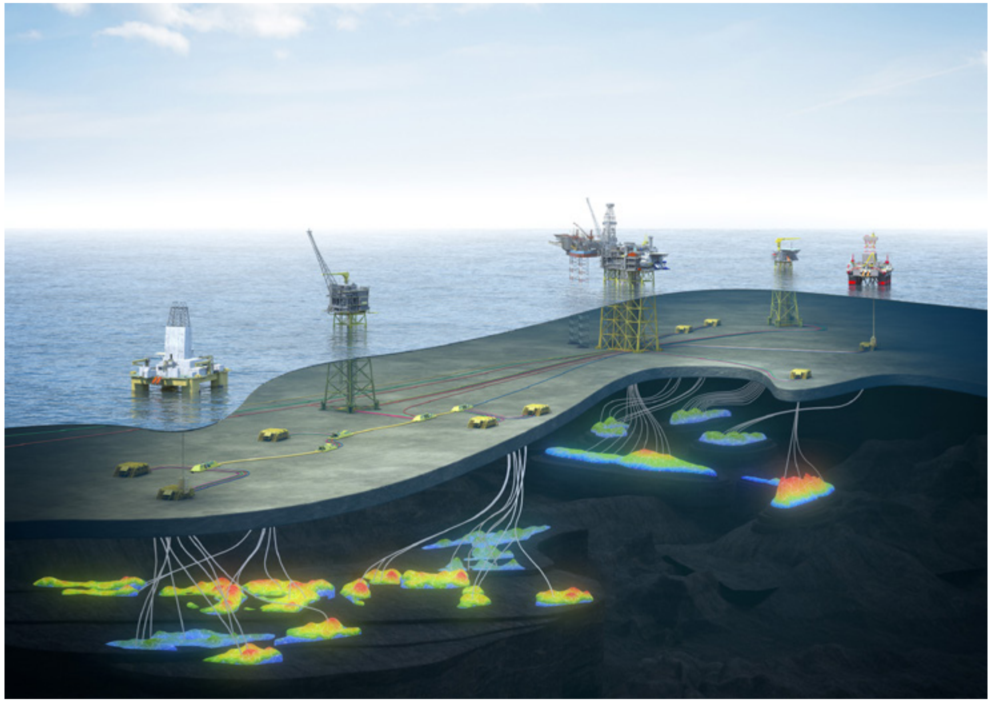


Figure 3.22 **The Yggdrasil area**

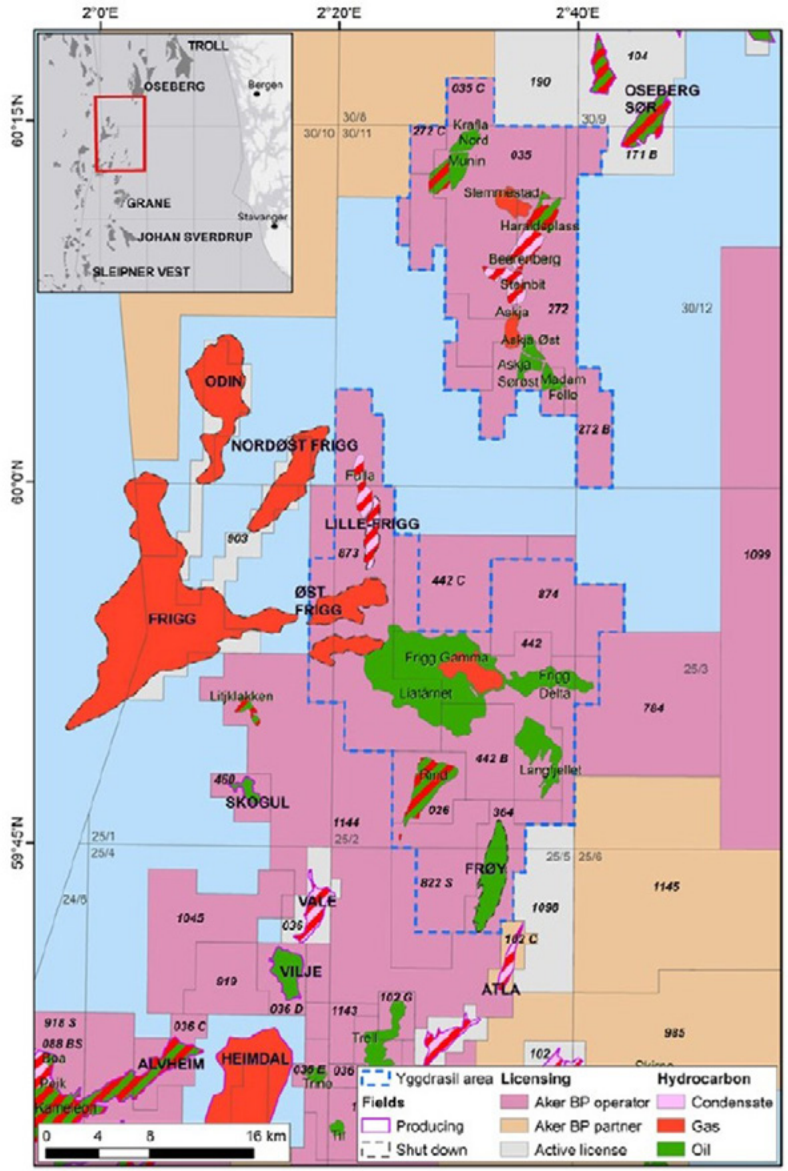
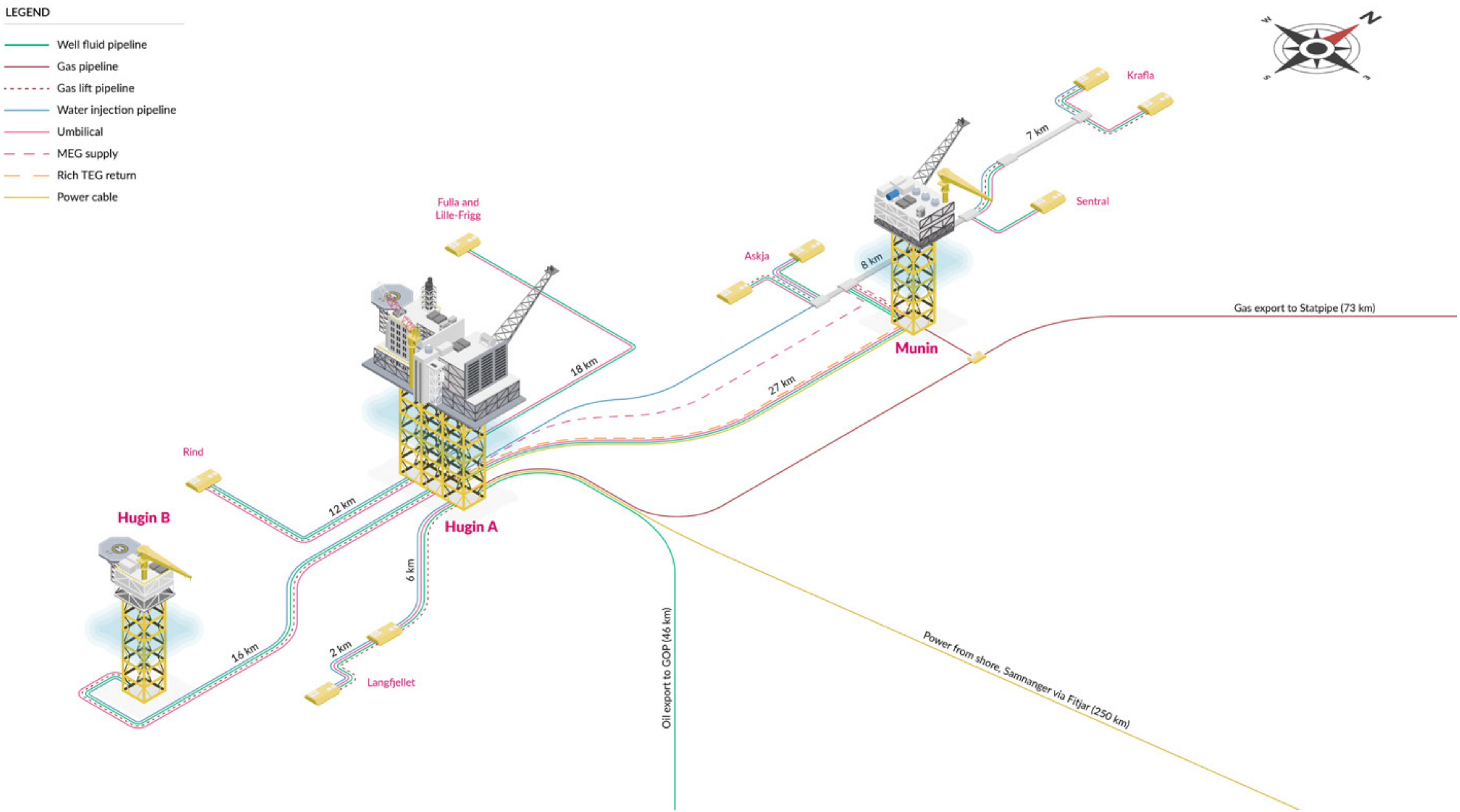


Figure 3.23 **Yggdrasil Area Development**



3.2.7 Frøy (PL364)

Discovery

The Frøy field was discovered by well 25/5-1 in 1987, followed by appraisal well 25/5-2 in 1989. The Frøy development was approved in May 1992, and the field was in production from 1995 to 2001, with Elf as the operator. During production, early water breakthrough and increasing water cut were observed, accompanied by a rising gas-oil ratio and declining well pressures. These challenges ultimately led to the decision to cease production in 2001, after producing 5.9 million standard cubic metres of oil and 1.7 billion standard cubic metres of gas.

Reservoir

The Frøy re-development targets the Middle Jurassic Hugin and Sleipner Formations, which were deposited in a range of fluvial to marginal marine environments with varying degrees of tidal influence. The resulting reservoir exhibits a complex architecture and highly variable properties, with significant contrasts in flow characteristics between different zones.

Development

The Frøy re-development comprises a 12-slot normally unmanned installation, the Hugin B platform, tied back to the Hugin A platform. Frøy will have six producers (slanted/horizontal) and two water injectors. Based on pilot results, an additional producer can be drilled in the Frøy NE prospect. The drainage strategy involves pressure support through water injection, with water supplied from the Hugin A platform.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Frøy are classified as “Reserves; Approved for development” (SPE’s classification system).

Aker BP holds a 87.7 percent interest in Frøy, with the remaining 12.3 percent held by ORLEN Upstream Norway AS.

3.2.8 Frigg Gamma Delta (PL442)

Discovery

The Frigg Gamma discovery well, 25/2-10 S, was drilled in 1986 with an appraisal well, 25/2-11, in 1987 which showed gas with a 14-metres thick oil column. The Frigg Delta discovery well, 25/2-17. was drilled in 2009 and found oil with no gas cap.

Reservoir

The Frigg Formation comprises gravity-driven deep marine sediments, both classical turbidites, debrites, and slumps, which are stacked in lobe complexes. The depositional lobes consist mostly of sandstones, but shaly interbeds can occur within the lobes.

The two different structures, Frigg Gamma and Frigg Delta, are connected through a common aquifer. Frigg Gamma has a thin oil column of 14 metres with an overlaying gas cap and an underlying strong aquifer. Frigg Delta contains undersaturated oil column with higher viscosity compared to Frigg Gamma.

Development

The Frigg Gamma Delta development includes 6 trilateral horizontal producers and 2 water injectors drilled from the Hugin A platform. The development strategy for Frigg Delta is oil production with pressure support from the aquifer, Frigg Gamma will rely on pressure support from the gas cap. The water injector’s primary purpose is to dispose of produced water from the Hugin A platform.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Frigg Gamma Delta are classified as “Reserves; Approved for development” (SPE’s classification system).

Aker BP holds a 87.7 percent interest in Frigg Gamma Delta, with the remaining 12.3 percent held by ORLEN Upstream Norway AS.

3.2.9 Langfjellet (PL442)

Discovery

Langfjellet was discovered by exploration well 25/2-18 with three entry points into the reservoir (A, C and S) in 2016, drilled by Aker BP. The well proved oil in sandstones of the Hugin Formation and condensate in the Sleipner Formation.

Reservoir

Variable sedimentary environments during its deposition and subsequent deep burial, has resulted in a reservoir characterised by contrasting and mostly marginal reservoir properties. Each of the Langfjellet discovery wells show variable oil pressures, water pressures and variations in oil gradients. The data shows that both vertical and lateral barriers are present, creating multiple compartments.

Development

Langfjellet will be developed with two 6-slot subsea templates that are tied-back to the Hugin A platform. Three producers, two water injectors and an infill (depending on result of a pilot well) well are initially planned, leaving six spare slots for future use. The producers are U-shaped or sinus-shaped wells with two or more deviated cuts across the oil-bearing stratigraphy, to mitigate any barriers in the reservoir.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Langfjellet are classified as “Reserves; Approved for development” (SPE’s classification system).

Aker BP holds a 87.7 percent interest in Langfjellet, with the remaining 12.3 percent held by ORLEN Upstream Norway AS.

3.2.10 Rind (PL442)

Discovery

The exploration well, 25/2-5, was drilled by Elf on the Rind Horst in 1976 and proved oil in Hugin Formation and Statfjord Group, and gas-condensate in the Sleipner Formation. An appraisal well, 25/2-13, targeting the western segment was drilled in 1990 and proved similar hydrocarbon types in the same formations.

Reservoir

The Hugin reservoir is approximately 100 metres thick and comprises shallow to marginal marine strata. The Sleipner reservoir, around 50 metres thick, consists of fluvio-deltaic and coal-bearing paralic strata. The deeper Statfjord reservoir is approximately 200 metres thick and is made up of fluvial to marginal marine strata. Due to its channelised nature and predominantly low permeability, the Statfjord reservoir is assumed to exhibit a relatively low degree of connectivity. The Statfjord reservoir is separated from Hugin/Sleipner by a 150-metre thick Dunlin shale.

Development

Rind will be developed using a six-slot subsea template tied back to the Hugin A platform. One producer will be a multilateral horizontal well, the other two producers will be single horizontal wells. The Statfjord producer will be completed with Fishbone technology to address the challenge of lower permeability. The two water injectors will provide pressure support to the field.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Rind are classified as "Reserves; Approved for development" (SPE's classification system).

Aker BP holds a 87.7 percent interest in Rind, with the remaining 12.3 percent held by ORLEN Upstream Norway AS.

3.2.11 Fulla and Lille-Frigg (PL873)

Discovery

Well 30/11-7, drilled by Statoil in 2008 on the Fulla structure, proved a lean gas-condensate in sandstones of the Ness Formation. The sidetrack, 30/11-7 A, proved the main gas-condensate accumulation in the Tarbert Formation.

Lille-Frigg was discovered in 1975 by Elf Aquitaine Norge, and the Plan for Development and Operation (PDO) was approved in 1991. The field was developed with a subsea installation with three production wells tied-back to the Frigg field Centre. Production started in 1994 but was stopped prematurely in 1999 due to water breakthrough and risk of hydrate formation in the pipelines. 2.3 GSm^3 of gas and 1.2 MSm^3 of condensate were produced. The installation was removed in 2001.

Reservoir

The Fulla & Lille-Frigg area consists of the Tarbert Formation which is mostly characterised by delta front and estuarine depositional environments.

The Tarbert Formation on both Fulla and Lille-Frigg is generally very sand-prone, with the best reservoir properties found in fluvial and/or deltaic distributary channel deposits.

Development

Fulla & Lille-Frigg will be developed through a 6-slot subsea template with a tie-back to the Hugin A platform. Both fields will be drained by natural pressure depletion through two slanted producers on Fulla and a horizontal producer in Lille-Frigg.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Fulla and Lille-Frigg are classified as "Reserves; Approved for development" (SPE's classification system).

Aker BP holds a 47.7 percent interest in Fulla & Lille-Frigg. The remaining interests are held by Equinor Energy AS (40 percent) and ORLEN Upstream Norway AS (12.3 percent).

3.2.12 Munin (PL272, PL035, PL035C)

Discovery

The Munin field was discovered in 1997 with well 30/11-5 followed up by numerous appraisal/exploration wells, making the total number of wells 11 plus 6 sidetracks. The Munin field now consists of 11 oil and gas discoveries in the Brent group, in the Tarbert Formation. The reservoirs are found in Upper and Middle Tarbert and Etive/Ness.

Reservoir

The Brent group was deposited as a major delta system comprising sandstone, siltstones, shale, calcite and coals. Deposition of the Tarbert Formation has occurred in the retrogradational phase of the Brent delta, generally in marginal marine estuarine environment or shallow marine environments, during early rift initiation.

Munin is divided into three areas: Krafla, Sentral and Askja.

Krafla has three proven segments: Krafla Vest, Krafla Midt, and Krafla Nord. Varying pressures, fluid phases and contacts have been observed across these compartments.

Sentral has three proven segments: Beerenberg, Slemmestad and Haraldsplass. There are different fluid types and contacts observed in these segments.

Askja has four proven segments: Askja Vest, Askja Øst, Askja Sørøst and Madam Felle. Askja Vest is separated from Askja Øst based on difference in fluid phase (gas/oil) and different pressures across a fault. Askja Øst is separated from Askja Sørøst by a likely sealing fault.

Development

The development will be with subsea templates at the Krafla, Sentral and Askja areas and tied-back to the Munin platform. There is two-phase separation on the platform. The gas is exported to Kårstø via Statpipe, and the liquid phases are pumped to the Hugin A platform at Frigg Gamma Delta.

In total, there will be 21 producers and three water injectors.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Munin are classified as "Reserves; Approved for development" (SPE's classification system).

Aker BP holds a 50 percent interest in Munin. The remaining interests are held by Equinor Energy AS.

3.2.13 Solveig Phase 2 (PL359)

Discovery

The discovery and appraisal history of Solveig is described in Chapter 3.1.9.

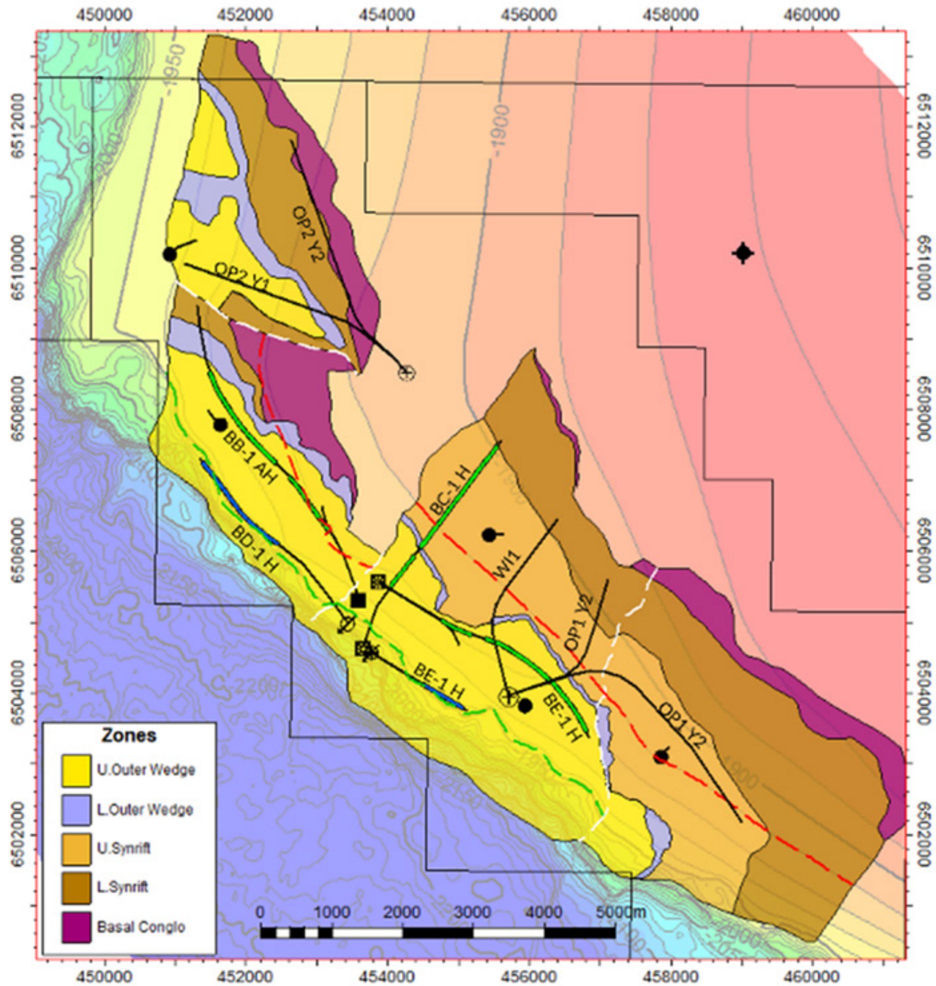
Reservoir

The Phase 2 development will focus on the Synrift reservoir with additional wells in Segment B, plus the inclusion of Segment A and Segment D into the development. Phase 2 will also target the Outer Wedge reservoir interval in Segment D. The reservoirs are described in Chapter 3.1.9.

Development

Solveig Phase 2 is a subsea tie-back to Edvard Grieg via the Solveig Phase 1 infrastructure. The tie-in connection points are the Solveig Phase 1 Pipeline End Manifold (PLEMs), which all have tie-in points for future expansion. The development consists of two drill centres, one is a single satellite, and the other is a template drill centre. The Solveig Phase 2 reservoir development is shown in Figure 3.24, with two MLT producers and one water injector.

Figure 3.24 **Solveig Phase 2 development wells shown in black**



Status
The Solveig Phase 2 development was sanctioned in December 2022. Development drilling is planned to start late in 2025, with first oil planned in 2026.

The recoverable volumes on Solveig Phase 2 are classified as "Reserves; Approved for development" (SPE's classification system). Minor positive adjustment after PDO related to well optimisation (water shut-off).

Aker BP holds 65 percent in Solveig. The remaining shares are held by OMV (Norge) AS 20 percent and Harbour Energy Norge AS 15 percent.

3.2.14 Symra (PL167 & PL167C)

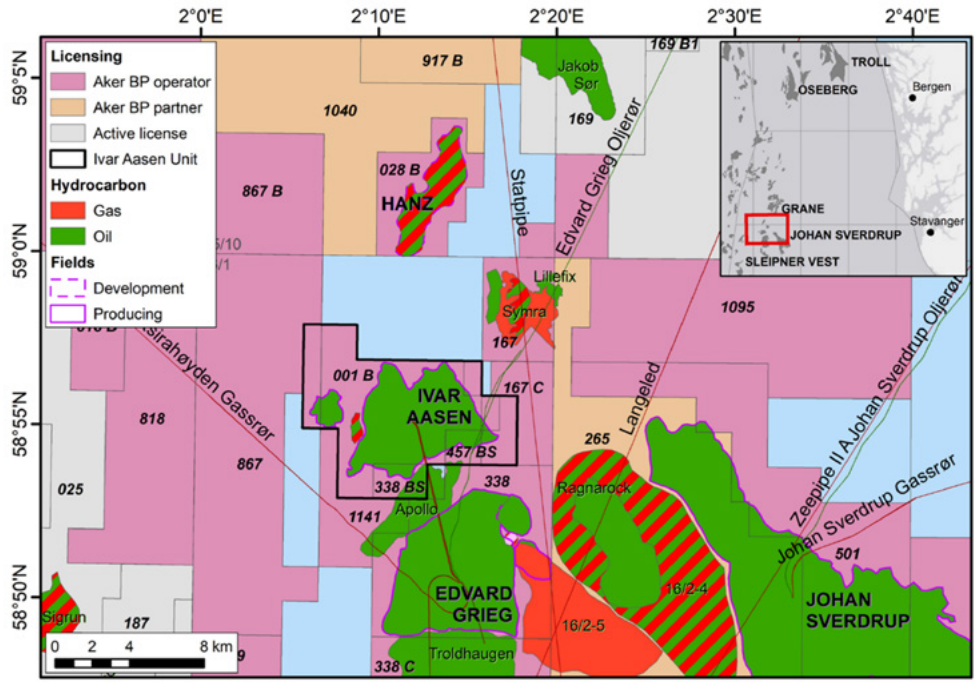
Discovery
The current PL167 / PL167C licensees are Aker BP (operator 50 percent), Equinor Energy AS (30 percent) and Sval Energi AS (20 percent). Symra (previously Lille-Prinsen) was discovered by the 16/1-6S (2003) well and appraised by 16/1-29 ST2 (2018), see Fig. 3.25. Appraisal well 16/1-34A (2021) confirmed oil in Zechstein carbonates, and a well test (DST) proved good reservoir connectivity/continuity. The upper Jurassic sandstones on the western flank of the high, also called "Outer Wedge" were discovered by appraisal well 16/1-30S (and geological sidetrack 16/1-30A) in 2019.

Reservoir
In PL167, the Symra structure includes several segments and reservoirs of different ages including Heather Formation sandstones, the Zechstein Formation carbonates and basement reservoirs.

The Heather Formation is penetrated by wells 16/1-30 S and 16/1-30 A in the Outer Wedge segment consisting of variable reservoir quality sandstone. The Zechstein carbonates were part of an extensive carbonate platform, which was eroded over most of the basement high. Basement is the largest reservoir in terms of bulk volume in the Symra area. It is included in the reservoir model given the commercial success of production from basement wells further south.

Development
The Symra field is planned as a subsea development, with tie-back to the host platform at Ivar Aasen (distance approximately 7.5 km). Final processing of the Symra oil and gas will occur at Edvard Grieg with export through the existing EG (and IA) oil and gas downstream transport system. The selected concept for the subsea layout is one 4-slot ITS/template and drill centre, with the SURF scope covering pipelines for oil, gas lift, water injection and umbilical. A defined upgrade scope is to be carried out at Ivar Assen, consisting of a new water injection pump and chemical injection skid, among other things. The reference case drainage strategy consists of four oil producers (three pre-drilled), Two of the oil producers can be converted to injectors (OWS and OW wells) and the Outer Wedge South well is converted into a water injector, 18 months post first oil.

Figure 3.25 **Symra location**



Status
The PDO was submitted in December 2022 and approved June 2023. First oil is expected in Q3 2026.

The recoverable volumes on Symra are classified as "Reserves; Approved for development" (SPE's classification system). A positive adjustment after PDO is related to earlier start-up, well optimisation and technical production profile including 2041.

3.2.15 Verdande

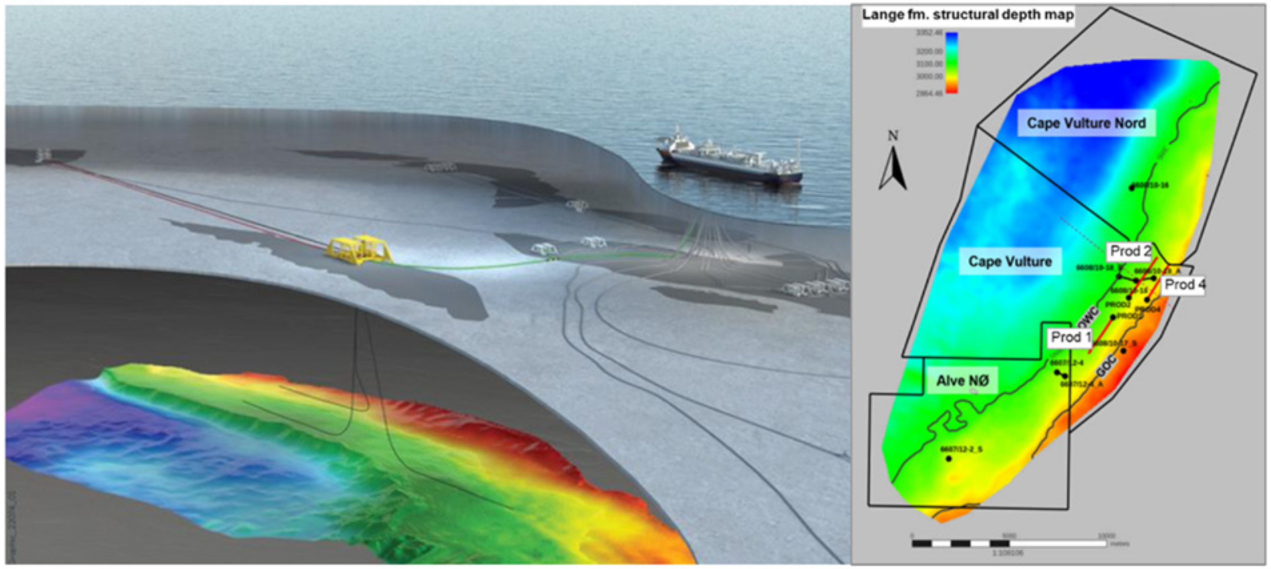
Discovery

The Verdande discovery well 6608/10-17S was drilled in 2017 and encountered an oil column with a gas cap in two levels in the Cretaceous Lange Formation, see Fig.3.26. The upper-level reservoir sandstone contained an 8-metres oil column while the lower reservoir contained 5-metres oil with a 13-metres gas column. The field was further appraised in 2018 with well 6608/10-18 and geological side-tracks 6608/10-18 A and B. During 2020, wells 6507/12-4 and 6507/12-4 A in the PL 127C were drilled and proved the Alve Nordøst discovery which extends across the licence boundary and is laterally larger than expected. Well 6507/12-4 encountered oil in Lange Fm in addition to primary Jurassic target. The geological side-track 6507/12-4 A, proved additional volumes in Lange Fm.

Reservoir

The field consists of two accumulations: Cape Vulture and Alve Nord Øst. It is positioned on the Dønna Terrace and has three reservoir units. The porosity ranges from 15 percent to 19 percent and permeability is 117 to 1561mD. The main uncertainties are poor connectivity and/or not optimal well placement.

Figure 3.26 **Outline of the Verdande project and placement of the 3 development wells**



Development

The field will be developed using three long horizontal oil producers drilled from a new four-slot template tied back to the Norne FPSO via a Tee connection to the Norne E flowline. Well control and gas lift are provided by an umbilical and flowline from the Skuld P template. The topside modification scope at the Norne FPSO is minor. The drainage strategy is a combination of pressure support from gas cap expansion and natural depletion.

Status

The PDO was submitted in December 2022 and approved in June 2023 with an agreed unitisation.

Verdande Development has been re-classified from "Justified for Development" to "Approved for Development". No other changes since last year. Cessation of production (CoP) is planned year-end 2029 in alignment with host Norne FPSO Cessation of production (CoP).

Aker BP holds 7 percent in the Verdande Unit. The remaining shares are held by Equinor Energy AS 59.2682 percent, Petoro AS 22.4067 percent, DNO Norge AS 10.4979 percent and ORLEN Upstream Norway AS 0.8272 percent.

The planned start of production is October 2025. The development drilling started 29 November 2024 and planned finished in April 2025.

4. Contingent Resources

Aker BP has contingent resources in a wide range of assets and at different stages of maturation. The total net contingent resources estimates reported here include volumes as defined in Figure 1.1. Discoveries that need more data acquisition to define the way forward, such as Rondeslottet and Liatårnet, are not included.

The contingent resources range from 508 to 1,142 mmboe, with a 2C volume of 802 mmboe. Approximately 4/5 of this is associated with discoveries and further development of the fields containing reserves described in 3 Description of Reserves. The most important contributors to the contingent resources in these areas are the discoveries in the Yggdrasil area and volumes in the Valhall area.

The most important discoveries outside the producing asset areas are Wisting, Alta/Gohta, Garantiana and Lupa.

The following is a short description of the most important projects within the company's core areas containing contingent resources.

4.1 CONTINGENT RESOURCES BY AREA

4.1.1 Alvheim Area

The most mature contingent resource in the Alvheim Area (resource category 5, "Development not clarified or on hold") is Froskelår Future.

Several less mature projects (resource category 7) exist as well, among them Caterpillar, Rumpetroll, Froskelår NE, Tir and Firfisle, in addition to immature infill targets in some of the producing structures.

The combined net contingent resource potential for the Alvheim Area ranges from 20 to 70 mmboe.

The Alvheim Area is actively being worked to add additional infill and development opportunities from resource category 7 and maintain a focused exploration strategy for potential prospect opportunities.

4.1.2 Edvard Grieg Area

Several projects have been identified in the Edvard Grieg area. These projects include further IOR-activities in Edvard Grieg, Ivar Aasen and Solveig as well as development of nearby resources to the existing fields.

The combined net contingent resource potential in the Edvard Grieg area ranges from approximately 40 to 130 mmboe.

The largest potential development so far identified is Troldhaugen.

Troldhaugen (PL338C & PL338E)

Troldhaugen is a field located in the PL338C/PL338E licences on the Utsira High in the Norwegian sector (blocks 16/1 and 16/4) of the North Sea. Ownership in the licences is aligned with Aker BP holding 80 percent (operator) and OMV (Norge) AS 20 percent. This alignment of ownership allows for optimising development of the two licences.

See Chapter 3.1.11 for more details.

Discovery and reservoir

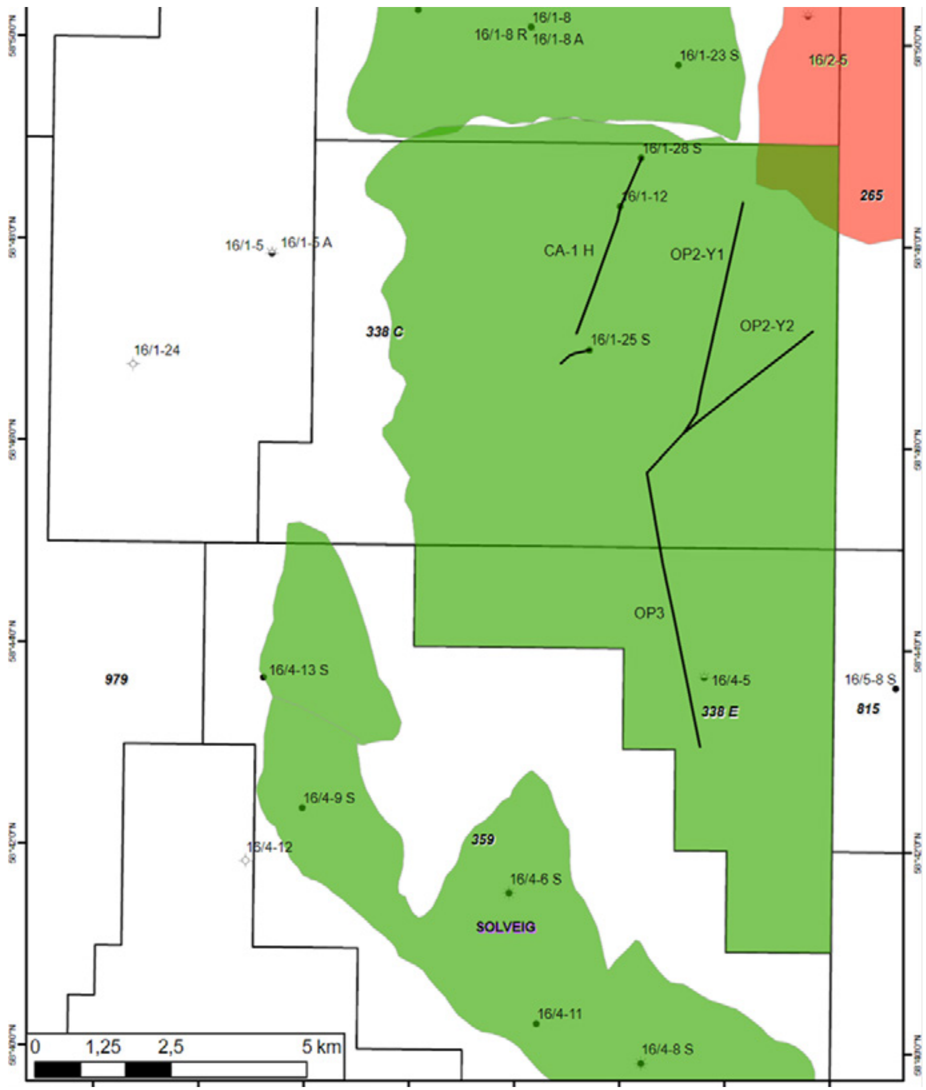
The Troldhaugen appraisal history and reservoir description is provided in Chapter 3.1.11.

Development

In addition to the existing CA-1H (EWT) well, the full field development is planned with two additional oil producers:

- OP-2 bilateral well in PL338C, Y-1 ~4km and Y-2 ~2.5 km long with branch control
- OP-3 4 km long single branch well in PL338E with three zones hydraulic smart completion

Figure 4.1 **Troldhaugen well locations map**



The two wells are planned drilled through an Integrated Template Structure (ITS). The ITS also provides two spare slots for future expansion of the development. The ITS is tied back to Edvard Grieg via the Troldhaugen EWT infrastructure 6 km to the north.

Status
A PDO was submitted in December 2022 with first oil planned for Q1 2026. The execution of the project was however conditional upon the performance of the extended well test. After the PDO was submitted, the experience from the well test resulted in a reduction in the expected recoverable volume for the project, and Aker BP therefore decided not to accede to the PDO. Since then the well test has continued, providing valuable information about the reservoir.

No volumes from the full field development have been booked as reserves in 2024.

4.1.3 The Ivar Aasen Area

Symra Area
The Palaeocene Heimdal prospectivity in PL167 is a distal pinch out of the Heimdal basin floor fan system, a stratigraphically trapped Heimdal sandstone within the Lista Formation shales. The Palaeocene Heimdal reservoirs have been encountered in the following wells: 16/1-6 S, 16/1-6 A, 16/1-29 S and most recently in 16/1-34 S and 16/1-34 A.

The Verdandi discovery, made in 16/1-6 S (2003), comprises gas within the Heimdal Member. The sidetrack 16/1-6 A encountered a water-up-to in the same formation. The Verdandi discovery was appraised in well 16/1-29 ST2 (2018) where samples were taken suggesting an oil leg present in Heimdal. The discovery was further appraised in 16/1-34 S (2021), which proved an oil column. These prospects will be further matured as part of the Symra development.

The Grid oil and gas discovery (2003-2021) within PL167, has been confirmed in several wells in the area. The discovery is comprised of oil and gas in thin, injected sandstones. Eocene Grid prospectivity 16/1-6 S (2003) discovered oil in the Grid Formation, while the Grid Formation sandstone in the sidetrack (16/1-6 A) was reported as dry. As for the Heimdal discovery, Grid will be further matured as part of the Symra development.

Licence partners are Aker BP as operator with 50 percent, Equinor Energy AS with 30 percent and Sval Energy AS with 20 percent.

4.1.4 The Yggdrasil Area

The contingent resources in Yggdrasil are spread over five fields as outlined below. The resources at Langfjellet and Frøy will be targeted by geo-pilot wells and the resources at Krafla, Sentral and Askja will be drilled as keeper wells, i.e. completed as a producer if a discovery is made. The Yggdrasil facilities are designed with flexibility to tie in the contingent resources with limited additional investment.

Contingent resources in Yggdrasil:

- Langfjellet 4b/5
- Frøy infill (NE & LP)
- Krafla
  - Eldfjel
- Sentral
  - Haukeland
  - Samantha
- Askja
  - Askja Nord
  - Magdalena
  - Katarina

A discovery in Frigg East was made during 2023 and is expected to be a considerable contribution to the Yggdrasil volumes.

The combined net contingent resource potential in the Yggdrasill Area ranges from approximately 50 to 150 mmboe.

4.1.5 The Valhall Area

Several projects have been identified which may significantly increase the reserves from the Valhall, Hod and Fenris fields. Some of the projects included in the resource classes 4 and 5 ("Development Pending" and "Development not Clarified or on Hold"), Figure 1.1, are listed below.

- Valhall South Flank Infills
- Valhall Flank West Waterflood
- Valhall PWP Technology Upside
- Valhall Redrills and Late Sidetracks
- Valhall Extended Production
- Valhall Diatomite Test Producer
- Hod field Development Expansion
- Fenris IUS
- Fenris Infill Wells
- Fenris extended production

Some of these projects may be approved by the end of 2025, while others are later life options (2030+).

Several projects in resource category 7 have also been identified, including further development of the diatomite reservoir, infill drilling and extended waterflood, EOR, etc. Pending further maturation, these projects are at present not included in the Valhall area contingent resources estimate below.

Aker BP holds 90 percent interest in all Valhall and Hod projects and 77.8 percent in Fenris.

The combined net resource potential in resource categories 4 and 5 for Aker BP in the Valhall Area ranges from approximately 100 to 230 mmboe.

4.1.6 Skarv Area

The combined net contingent resource potential for the Skarv Area ranges from approximately 20 to 85 mmboe.

The contingent resources in resource category 4 and 5 (“Development Pending” and “Development not Clarified or on Hold”, ref Fig.1.1) and category 7 (“Development not clarified”) in the Skarv area are:

Lunde (Shrek)

The reservoir was discovered by well 6507/5-9 S and is a high-quality unconsolidated oil reservoir with gas cap. Aker BP holds 35 percent interest in Lunde, together with ORLEN Upstream Norway AS with 35 percent interest and Lime Petroleum AS with 30 percent interest.

The plan for Lunde is to drill an extended reach well from the B/C template on Skarv and drain the gas cap. A PDO may be submitted in 1Q25 with planned drilling and production start in 4Q25.

Adriana/Sabina

Production Licence 211 CS Adriana and Sabina are discoveries located south of, and close to, the existing Ærfugl development and the Skarv FPSO. Adriana and Sabina were discovered when drilling well 6507/4-2S in the PL211 in 2021. Adriana and Sabina are discoveries in the Lysing Fm and Lange Fm respectively. The discoveries contain wet gas, condensate, and oil. Harbour Energy Norge AS is operator of Adrian/Sabina with 38.0825 percent interest. Aker BP holds 15 percent interest together with ORLEN Upstream Norway AS with 11.9175 percent interest and Petoro AS with 35 percent interest. Planned production start is 2029.

Storjo

Storjo was discovered by well 6507/2-6 and appraised by 6507/2-7 S in 2024. It is located west of the Skarv field and consists of Lysing and Tilje reservoirs. The plan is to develop Storjo with horizontal producers on depletion, through a template tied back to the SSP central manifold going into Skarv FPSO. Planned production startup is currently in 2029. The project passed DG0 in 2023 and DG1 is planned for 1Q 2025.

Aker BP (operator) holds 70 percent interest in the Storjo license, together with Harbour Energy Norge AS with 30 percent interest

Newt

Newt was discovered by well 6507/3-15 and is located northeast of Idun and the Skarv field. Newt consist of Fangst and Båt group formations of good reservoir quality. Fluid is oil with gas cap. Opportunities to develop with nearby prospects are being investigated.

Aker BP (operator) holds 70 percent interest in the Newt license, together with Harbour Energy Norge AS with 10 percent interest and ORLEN Upstream Norway AS with 20 percent interest

Skarv CO_2 reduction project

A CO_2 reduction project is being evaluated for Skarv.

Skarv Area IOR/IGR

The Skarv Area is actively being worked to add additional infill and development opportunities from resource category 7 and maintain a focused exploration strategy for potential prospect opportunities. These include infill wells in Tilje C and Ærfugl.

Continued development of Skarv and potential new tie ins could trigger extension of the FPSO technical lifetime beyond 2036.

4.1.7 Ula Area

At present no contingent volumes are recorded on Ula.

4.1.8 Partner-Operated Assets

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 3600 metres TVD MSL in the northern North Sea. The reservoir is high pressure (630 bar) with somewhat challenging fluid characteristics (high pour point temperature, unstable asphaltene and H2S content).

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

The discovery will most likely be developed as a subsea tie-back to Snorre B.

An exploration well was drilled in Q2 2021 in the Garantiana West segment. This is an oil discovery in the Cook formation with good reservoir quality. There is an improved fluid type observed at Garantiana West. Garantiana West will most likely be developed as a satellite structure tie-in to Garantiana.

The Angulata Brent prospect was drilled early 2023 but was dry. Three exploration wells are planned in 2025. Prospect Skrustikke is planned to be drilled early 2025 and Avbitertang and Narvi planned to be drilled late 2025.

Updated total Garantiana volume estimates indicate a net resource potential ranging from 12 to 27 mmboe to Aker BP (Cessation of production, CoP, 2045).

Equinor Energy AS is the operator and Aker BP holds 30 percent share in PL554.

Wisting (PL537 and PL537B)
The Wisting field includes oil discoveries in the Wisting Central and Hanssen compartments; located in the Hoop Fault complex, in the Barents Sea.

The 7324/8-1 (Wisting Central) and 7324/7-2 (Hanssen) discoveries were made in September 2013 and July 2014.

A total of seven wells have been drilled in the Wisting license.

Oil has been proven in the late Triassic to Middle Jurassic sediments in Realgrunnen Sub-group, the Stø, Nordmela and Fruholmen Formations. The main reservoir (Stø Formation) gross thickness is ~25m and it is characterized by excellent reservoir properties (2-4D). The apex of the field is estimated to be approximately 600 metres TVD MSL, and the free water levels (FWL) encountered are in the range of 690-698 metres TVD MSL. The Wisting reservoir has normal pressure (~70 bar) and low temperature (~17 °C).

The water depth is approximately 400 metres.

Volume estimates for Wisting Central and Hansen indicate a net resource potential ranging from 126 to 196 mmboe to Aker BP. The discovery will most likely be a stand-alone development with an FPSO (Floating Production Storage and Offloading vessel).

Equinor Energy AS is the operator and Aker BP holds a 35 percent share in PL537 and PL537B.

4.1.9 Other Discoveries
Other resources classified as contingent resources include discoveries that are either outside of asset areas or have not yet reached a high level of maturation, such as the Barents Sea discoveries (Alta, Gotha, Lupa) and Ofelia, Carmen, Ringhorne Nord, Enniberg, Norma and Busta. Volumes estimates range from approximately 100 to 200 mmboe.

Ofelia (PL929)
Ofelia discovery well 35/6-3 was drilled in 2022, and an appraisal well was drilled in the northern part of Ofelia in 2023.

Ofelia is located in block 35/6 in the Northern North Sea approximately 14 km North of the Gjøa field G-template and Ofelia development is planned as a subsea tie-back to the Gjøa facility.

Carmen (PL1148)
Carmen was discovered in July 2023 by exploration well 35/10-10 S and sidetrack 35/10-10 A.
The discovery is located within viable tie-back distance of several producing fields and hosts, including Troll/Fram to the east, Kvitebjørn and Gullfaks to the west and Vega, Gjøa to the northeast. Several other discoveries have been made in the surrounding area (including Atlantis and RVV-area discoveries) and possible cooperation with these projects are evaluated in the license.

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 reserves and resource accounting is coordinated and quality-controlled by a small group of professionals, led by a reservoir engineer with more than 30 years of experience in such assessments.

Additionally, all volumes within the reserve category (except for the minor volumes in the Enoch-field) have been certified by an independent third-party consultancy (AGR Petroleum Services AS). All production and cost profiles are included in AGR's certification report for completeness and assessment of economic cut-off with Aker BP SPE PRMS price assumptions.

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 based on expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves in a field or project is set at the time when the maximum cumulative net cashflow for each project occurs. The company has used a long-term inflation assumption of 2.0 percent, and a long-term exchange rate of 10, 9.5 and 9.0 NOK/USD in 2025, 2026 and 2027, respectively, and 8.5 NOK/USD thereafter. Oil prices of 77 USD/bbl (2025), 71 USD/bbl (2026-2035) and 66 USD/bbl thereafter have been used.

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 shut down producing fields early and lead to lower production. Higher oil prices may extend the life of the fields beyond current assumptions.

Karl Johnny Hersvik
CEO

Design: Headspin