Annual statement of reserves and resources

OKEA ASA – 2023

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1 Introduction

The Annual Statement of Reserves and Resources (ASR) is a full overview of the hydrocarbon volumes entitled to OKEA ASA ("OKEA") and has been prepared for both internal and external stakeholders. The reserves calculations and reporting are in line with the *Listing and Disclosure Requirements for Oil and Natural Gas Companies* as stated by Oslo Børs (Oslo Stock Exchange).

The overview in this document is the final version of the ASR 2023, with cut-off date 31 December 2023.

2 Classification of reserves and contingent resources

OKEA's reserves and contingent resources have been classified in accordance with the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE). This classification system is consistent with Oslo Børs' requirements for disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in *Figure 1*.

For completeness, OKEA reports not only 1P and 2P reserves, but also 3P reserves, as well as contingent resources. All categories are reported in line with the PRMS.

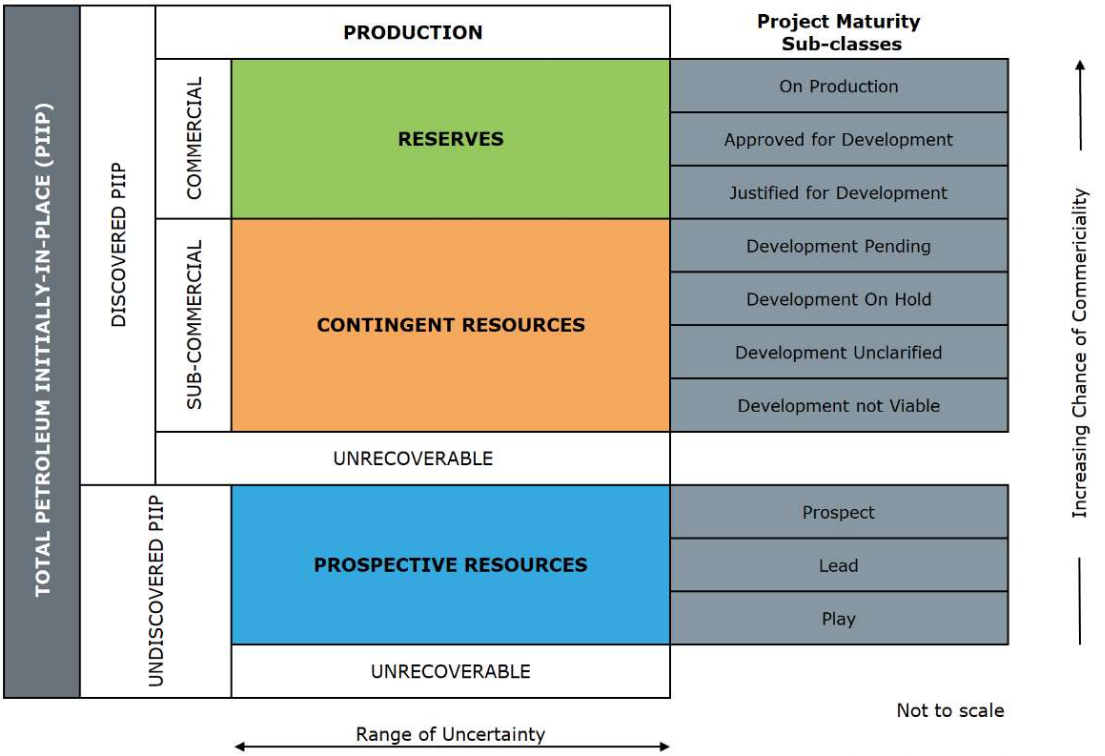

Figure 1: PRMS including sub-classes based on maturity

3 Reserves

OKEA ASA has reserves distributed across ten fields, listed in *Table 1*. The project status category describes the maturity for each of the fields and projects according to the PRMS, c.f. *Figure 1*. Reserves categorised as “Approved for development” correspond to field developments for which the Plan for Development and Operations (PDO) is approved by the Ministry of Energy or an exemption from this has been given.

Table 1: OKEA asset portfolio with reserves as of 31 December 2023

Field/Project	OKEA Working Interest	Operator	Project Status Category	Comment
Draugen	44.56 %	OKEA ASA	On production	Includes Hasselmus
Brage	35.2 %	OKEA ASA	On production	
Gjøa	12 %	Neptune Energy Norge AS	On production	
Ivar Aasen	9.2385 %	Aker BP ASA	On production	
Yme	15 %	Repsol Norge AS	On production	
Nova	6 %	Wintershall Dea Norge AS	On production	
Statfjord	28 %*	Equinor Energy AS	On production	New in OKEA portfolio
Statfjord Øst	14 %	Equinor Energy AS	On production	New in OKEA portfolio
Statfjord Nord	28 %	Equinor Energy AS	On production	New in OKEA portfolio
Sygna	15.40 %	Equinor Energy AS	On production	New in OKEA portfolio

*) in relation to the Norwegian part of the Statfjord field, c.f. section 3.3.7

The reserves estimates are based on all technical data available including production data, logs, seismic data, cores, models, decline curve analysis etc.

For economic evaluations, the long-term oil price assumption is 72 USD/bbl, with a long-term currency rate of USDNOK 9.0. Gas price and NGL price are set to 3.27 NOK/Sm^3 and 517 USD/tonne, respectively. All prices are in real 2023 and a 2% annual inflation rate is used.

Gas reserves are reported as sales gas with an energy content of 40 MJ/Sm^3.

In addition, the following conversion factors are used:

Oil - 1 Sm^3 = 1 Sm^3 oe = 6.29 bbl

Gas - 1 000 Sm^3 gas = 1 Sm^3 oe

1 Sm^3 = 35.315 Scf

NGL - 1 tonne NGL = 1.9 Sm^3 oe

3.1. Total reserves estimates

OKEA's net proven reserves (1P/P90) as of 31 December 2023 are estimated at 59.2 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 83.2 million barrels of oil equivalents. The reserves figures account for the effects of production in 2023. The split between oil, NGL and gas, and between individual assets is given in *Table 2*.

Table 2: OKEA reserves as of 31 December 2023 in mmboe

Asset/Project	OKEA WI	1P/P90 (Low estimate)				2P/P50 (Base estimate)			
		Gross Oil	Gross NGL	Gross Gas	Net OE	Gross Oil	Gross NGL	Gross Gas	Net OE
Reserves – On Production									
Brage	35.20 %	2.01	0.22	0.61	**1.00**	4.52	0.68	1.88	**2.49**
Draugen	44.56 %	37.54	1.80	7.09	**20.69**	41.71	1.96	9.38	**23.64**
Gjøa	12 %	0.70	4.16	17.73	**2.71**	1.11	5.38	22.87	**3.52**
Ivar Aasen	9.2385 %	32.29	1.88	5.76	**3.69**	38.47	2.97	9.09	**4.67**
Nova	6 %	30.38	5.82	11.28	**2.85**	47.50	7.81	14.70	**4.20**
Statfjord	28 %	16.28	6.88	18.91	**11.78**	27.85	12.48	34.31	**20.90**
Statfjord Nord	28 %	12.14	0.31	0.73	**3.69**	23.41	0.60	1.41	**7.12**
Statfjord Øst	14 %	11.40	1.40	3.57	**2.29**	19.23	2.32	5.92	**3.85**
Sygna	15.4 %	1.36	0.00	0.00	**0.21**	2.34	0.00	0.00	**0.36**
Yme	15 %	16.12	0.00	0.00	**2.42**	22.96	0.00	0.00	**3.44**
Total Net					**51.3**				**74.2**
Reserves – Approved for Development									
Brage - Talisker East	35.20 %	0.79	-0.02	-0.06	**0.25**	1.29	-0.04	-0.02	**0.44**
Draugen - Power from Shore	44.56 %	0.00	0.37	3.97	**1.93**	0.00	0.37	3.97	**1.93**
Draugen - Lifetime to 2040	44.56 %	10.12	0.45	0.75	**5.04**	11.13	0.49	0.82	**5.55**
Gjøa - LLP	12 %	0.18	0.88	3.98	**0.61**	0.30	1.54	6.94	**1.05**
IAA - Back out from Hanz	9.2385 %	0.68	0.03	0.10	**0.07**	0.68	0.03	0.10	**0.07**
Total Net					**7.9**				**9.0**
Reserves – Total									
Total Net					**59.2**				**83.2**

The reserves numbers are verified by a third party reserves certification performed by AGR Petroleum Services AS. Please note that totals in tables above are arithmetic and not stochastic summations.

The corresponding 3P/P10 estimate of net OKEA reserves is 106.0 mmboe. For comparison, the corresponding Total Net 1P-, 2P- and 3P-reserves in ASR 2022 (31 December 2022) were 45.5, 60.2 and 69.4 mmboe, respectively, c.f. *Table 3*.

The reserves estimates are essentially based on figures in the RNB2024 files reported by the operator of the individual assets. For Yme, however, OKEA's own estimates – somewhat more conservative than RNB2024 - are used. For Yme and for Brage, economic cut-off results in significantly lower reserves than the technically recoverable resources.

3.2. Development of reserves

OKEA's reserves and resources continually change through field development work, improvement of technical subsurface models, acquisitions, and production. *Table 3* illustrates how the volumes have changed since ASR 2022 (31 December 2022).

Table 3: OKEA reserves development from 31 December 2022 to 31 December 2023 in mmboe

Asset	EoY 2022		Production		Acquisitions/ Disposals		Revisions of previous estimates		Projects matured		EoY 2023	
	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Brage	**2.96**	**3.79**	-1.80	-1.80	-	-	-0.98	-1.33	1.07	2.28	**1.25**	**2.94**
Draugen	**28.28**	**31.85**	-2.34	-2.34	-	-	1.73	1.61	-	-	**27.66**	**31.12**
Gjøa	**2.66**	**4.93**	-2.09	-2.09	-	-	2.14	0.68	0.61	1.05	**3.32**	**4.58**
Ivar Aasen	**4.26**	**5.90**	-1.10	-1.10	-	-	0.60	-0.06	-	-	**3.76**	**4.74**
Nova	**3.65**	**5.48**	-0.58	-0.58	-	-	-0.22	-0.70	-	-	**2.85**	**4.20**
Statfjord	-	-	-	-	11.78	20.90	-	-	-	-	**11.78**	**20.90**
Statfjord Nord	-	-	-	-	3.69	7.12	-	-	-	-	**3.69**	**7.12**
Statfjord Øst	-	-	-	-	2.29	3.85	-	-	-	-	**2.29**	**3.85**
Sygna	-	-	-	-	0.21	0.36	-	-	-	-	**0.21**	**0.36**
Yme	**3.73**	**8.22**	-1.01	-1.01	-	-	-0.31	-3.77	-	-	**2.42**	**3.44**
Total	**45.5**	**60.2**	-8.91	-8.91	17.97	32.22	2.96	-3.56	1.67	3.33	**59.2**	**83.2**

"Acquisitions" are related to acquisitions of working interests in Statfjord, Statfjord Nord, Statfjord Øst and Sygna in 2023. Since the completion date of this acquisition was 29 December 2023, production in 2023 is excluded for these assets.

The revision on Yme is primarily related to disappointing results from the well C-8 (drilled in 2023) and early economic cut-off. Gjøa maturation is linked to approval of the LLP-measure. Brage maturation is linked to approval of 4 well projects (A-13 F, A-37 C, A-30 C, and A-11 E).

3.3. Description of reserves

The following section describes fields on production and fields approved/justified for development where OKEA holds a working interest.

3.3.1. Draugen (PL093)

The Draugen field is in the Norwegian Sea, approximately 140 km Northwest of Kristiansund, in 250 meters water depth, c.f. *Figure 2*.

Discovery

The field was discovered by well 6407/9-1 in 1984, proving oil in the Rogn formation. This was the first discovery in Rogn on the Haltenbanken terrace.

Reservoir

The oil is in the Garn and Rogn formations, of which the latter holds approximately 90% of the reserves. The reservoir quality is excellent, with average permeability of more than 2 Darcy. The best well, A-4 A, has the offshore world record oil production rate reaching a peak of 77 000 bbl per day.

Development

The field is developed with a concrete gravity-based structure (GBS), with full oil stabilisation and storage capabilities. Oil is exported by shuttle tankers. Since the "Draugen long-term power project" was implemented in 2020, gas can now be both exported and imported through the gas pipeline connected to the Åsgard Transport System (ÅTS).

The drainage strategy is based on centrally located production wells, supported by down-flank water injectors. The field was initially developed with 6 platform wells and 1 subsea well and has later been supplemented by several subsea wells. The platform wells have gas lift, while the subsea wells are produced via a subsea booster pump to lower the tubing head pressure.

Status

The current production on Draugen is in the order of 15 500 bbl of oil and 220 000 bbl of water per day. 110 000 bbl of water are reinjected to the reservoir, while the rest is discharged to sea. Gas and NGL are exported through ÅTS.

Currently, 5 out of 6 platform wells and 9 out of ten subsea wells are producing, in addition to 2 subsea water injectors. One subsea well (G-3 H) - injecting condensate until 1 October 2023 – is currently shut in. D-1 AH is shut in due to high water cut. Subsea wells G-1 H, G-2 H, G-5 H and all E-wells produce on reduced choke setting to maintain reservoir pressure. Production is continuously monitored and optimised by a production management team.

The reserves estimates are based on the RNB2024 submission by OKEA, assuming production until end of economic field lifetime at end of 2040. Note that the lifetime of the field has been extended as a consequence of the Power from shore project, see below.

Some of the projects that contribute to the Draugen reserves are discussed below. Contingent resources related to the Draugen field are described in Section 4 and 5, respectively.

OKEA's working interest on Draugen is 44.56%. The other licensees are Petoro AS (47.88%) and M Vest Energy AS (7.56%).

Hasselmus

Hasselmus is a gas accumulation above a 5.5 meters oil leg, 7 km northwest of the Draugen field, c.f. *Figure 2*. The structure was discovered by well 6407/9-9 in 1999 and is now part of the Draugen field.

The reservoir is a sand-prone interval of tidally influenced shallow marine deposits, interpreted to be laterally continuous with high Net to Gross ratio, close to 100% in the gas zone. Seismic interpretation indicates that the reservoir is not affected by any major internal faults.

Hasselmus is drained by a single vertical gas producer well, placed close to the crest of the structure. Gas expansion will be the main driving mechanism, possibly assisted by limited aquifer support. The oil leg will not be recovered.

Hasselmus is tied back to the Draugen platform via a subsea pipeline. To cater for future tie-ins from third party licences, a pipeline end manifold (PLEM) has been included in the design. Topside modification includes a re-bundling of the main export compressor, as well as heater and scrubber for the Hasselmus gas.

Hasselmus started production 1 October 2023, associated export volumes are reported as reserves.

Restart of gas export

The Hasselmus development provides sufficient gas to meet Draugen's fuel consumption requirement and thereby allowed for restart of gas export from Draugen. Accordingly, expected

NGL volumes produced from the Draugen field that are evacuated through the Åsgard transport system after Hasselmus start-up are reported as reserves.

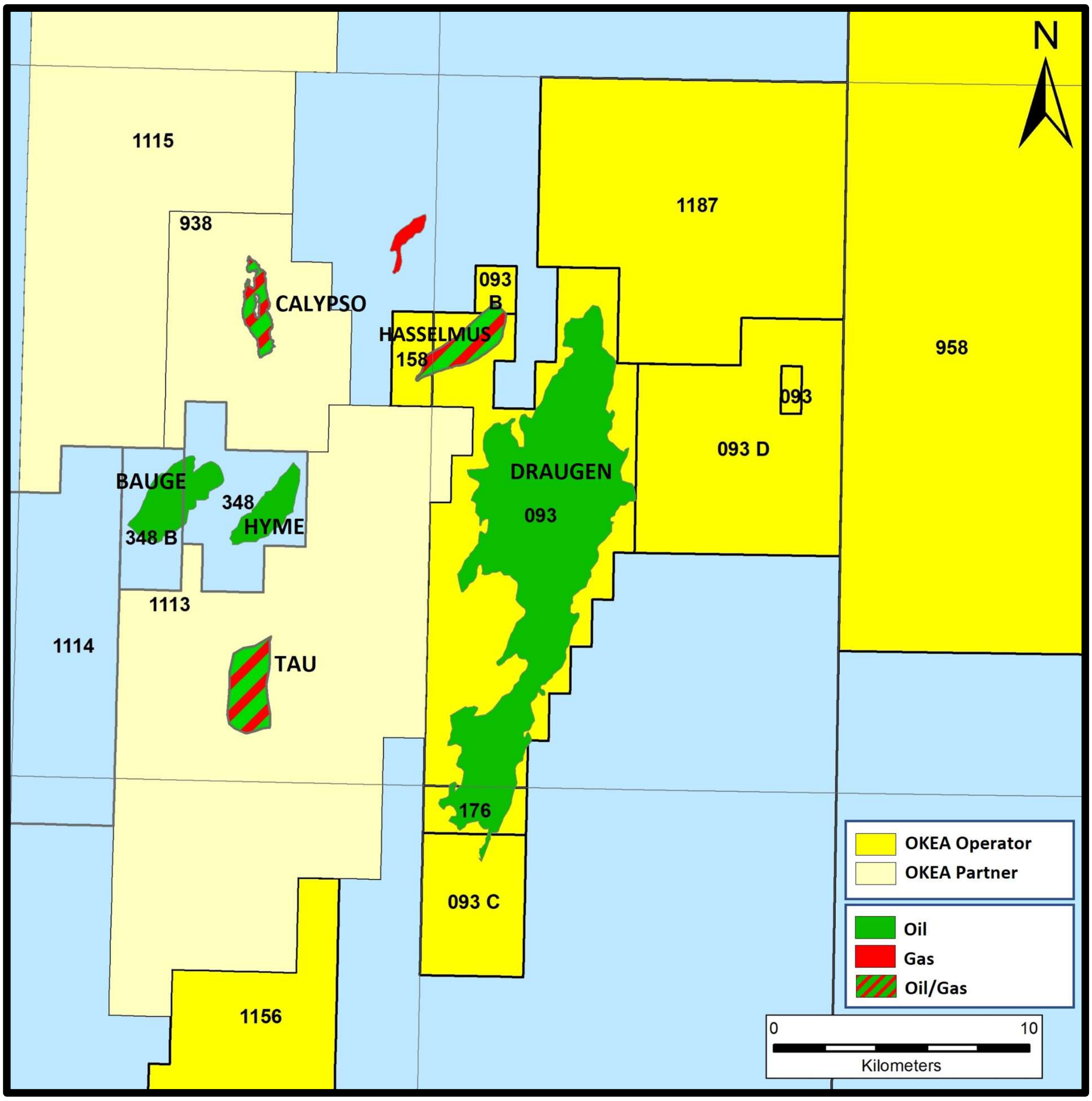

Figure 2: Draugen field location and adjacent area (Norwegian Sea)

Power from shore

The project "*Norskehavet Sør Kraftanlegg*" shall provide electric power from shore (PfS) to both the Draugen field and the Njord field. The project was sanctioned (DG3) by the Draugen license and the Njord unit in December 2022. Authority approval was obtained on 22 December 2023. This measure will not only reduce emissions from the two platforms drastically, but also result in reduced OPEX and allow higher gas export from Draugen.

Lifetime to 2040

As a direct consequence of the PfS-project being sanctioned and approved, the economic lifetime of the field is extended to end of year 2040, yielding increased reserves.

3.3.2. Brage (PL055)

The Brage field is located in the North Sea, 125 km west of Bergen and between the Troll and Oseberg field at a water depth of 140 meters, c.f. Figure 3.

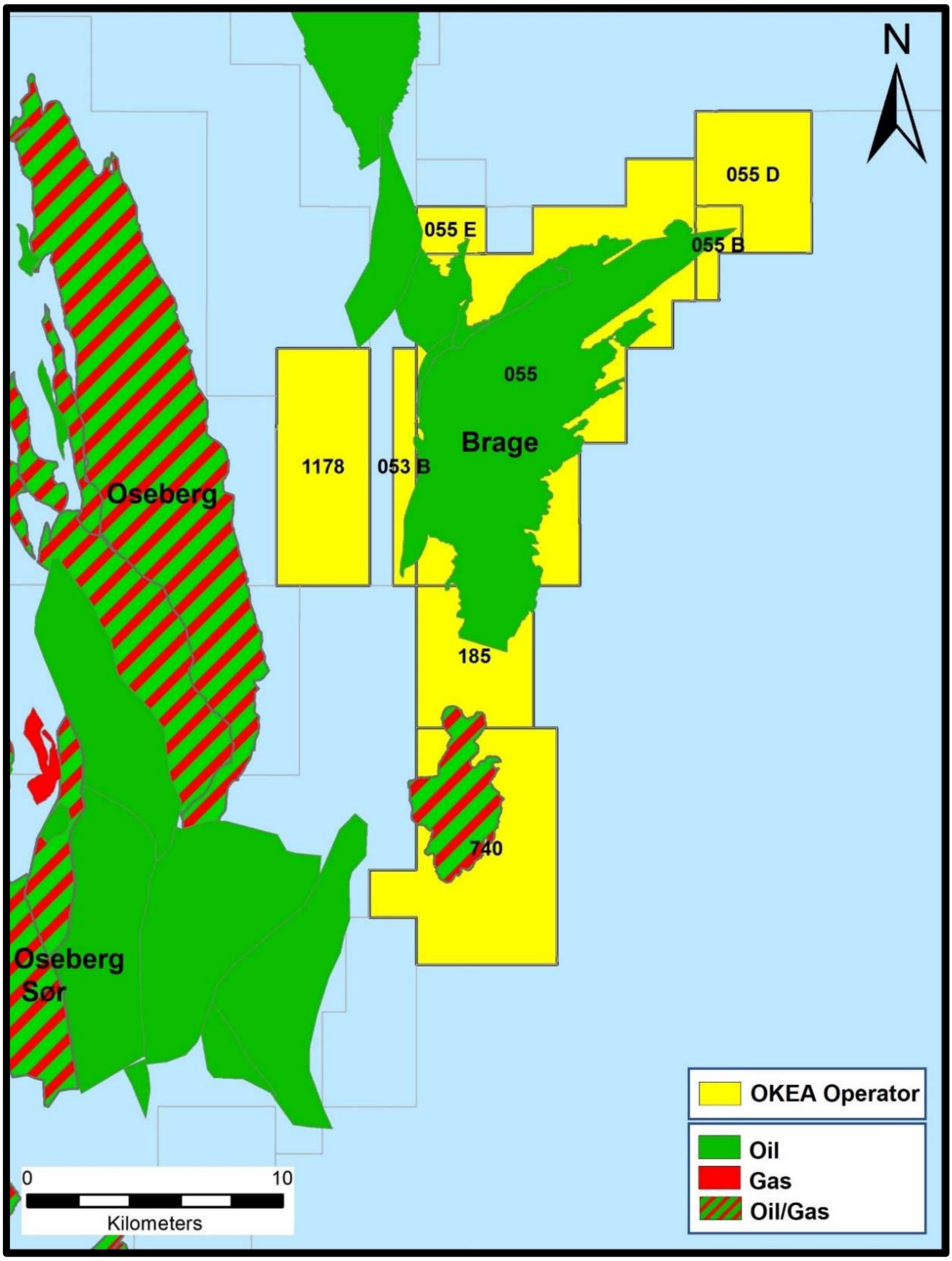

Figure 3: Location of the Brage Unit and adjacent area (North Sea)

Discovery

The Brage field was discovered with well 31/4-3 in 1980, proving oil and gas in Jurassic sandstones.

Reservoir

Brage produces oil from sandstones of Lower Jurassic age in the Statfjord Group and Cook Formation, and sandstones of Middle Jurassic age in the Brent Group and the Fensfjord Formation. There is also oil and gas in Upper Jurassic sandstones in the Sognefjord Formation. The reservoirs lie at a depth of 2,000-2,300 meters. The reservoir quality varies from poor to excellent.

Development

Brage is a field in the northern part of the North Sea, ten kilometers east of the Oseberg field. The water depth is 140 metres. Brage was discovered in 1980, and the plan for development and operation (PDO) was approved in 1990. The field has been developed with an integrated production, drilling and accommodation facility with a steel jacket. Production started in 1993. A PDO for Brage Sognefjord was approved in 1998. The authorities granted PDO exemptions for the Brent Ness and Bowmore Brent deposits in 2004 and 2007, respectively. PDO exemptions for Talisker and Cook were approved in 2022 and 2023, respectively.

The Brage field is currently producing from five different reservoirs with different reservoir characteristics and recovery methods:

The Statfjord Formation, divided into a northern and southern segment by a fault, is a braided river system with very good sand quality. Due to the limited natural pressure support, water injection is required to maintain reservoir pressure. The Cook Formation is a prograding shelf system with medium to low sand quality. The drainage strategy for Cook is production by pressure depletion. The shallow-marine Fensfjord Formation consists of sands of varying properties and internal flow barriers. The reservoir is highly heterogeneous. Pressure support is mainly provided by aquifer. The Sognefjord reservoir (Draupne/Sognefjord sands) consists of alternating layers of relatively good permeability sands and poor-quality silty sands deposited in a shallow marine depositional system. Pressure support is mainly provided by aquifer. The lower part of the Brent reservoir (Oseberg) is deposited in a shallow marine setting. The reservoir consists of good quality sands with Darcy permeability. The drainage strategy is depletion with pressure support from aquifer in addition to water injection in Upper Ness (A-22 A) on the Bowmore segment. In the Talisker segment (Brent Oseberg), A-11 E has been producing since May 2023 by pressure depletion and pressure support from aquifer. A water injection well (A-40 C) is currently being drilled which will provide pressure support to the Brent reservoir on Talisker.

Oil is transported by pipeline to the Oseberg field and further through the Oseberg Transport System (OTS) pipeline to the Sture terminal. A gas pipeline is tied-back to Statpipe transporting rich gas to Kårstø for processing and further export.

Status

The current production on Brage is in the order of 22 300 bbl of oil and 144 000 bbl of water per day. 110 000 bbl of water are reinjected to the reservoir, while the rest is discharged to sea. In addition, 60 000 bbl water from Utsira is injected into the reservoir. Currently, Brage is producing from 18 producers (including A-13 F, A-30 C, A-37 C) and injecting water in 4 injectors. In addition to these, there are also one Utsira water producer for water injection and one CRI injection well. Production is continuously monitored and optimised by a production management team.

OKEA’s working interest on Brage is 35.2%. The other licensees are Lime Petroleum AS (33.84%), DNO Norge AS (14.26%), Vår Energi ASA (12.26%) and M Vest Energy AS (4.44%).

3.3.3. Gjøa (PL153)

The Gjøa field is in the northern part of the North Sea, 50 kilometres northeast of the Troll field, in the PL153 license, c.f. *Figure 4*. Water depth in the area is 360 meters.

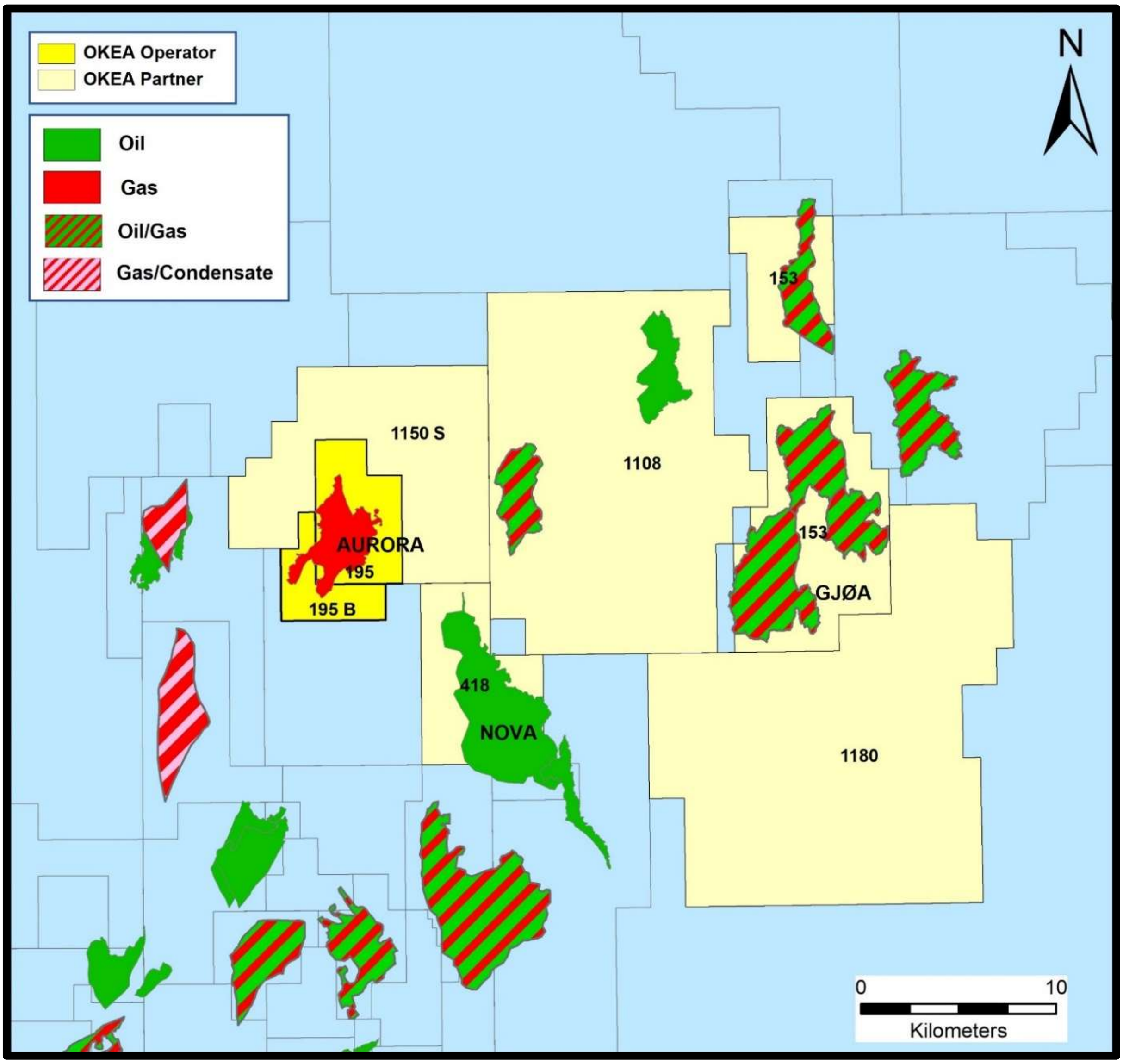

Figure 4: Gjøa field location and adjacent area (North Sea)

Discovery

The field was discovered by exploration well 35/9-1 / 35/9-1 R in 1989, confirming gas in the Viking Group and Brent Group, and oil in the Dunlin Group.

Reservoir

The Gjøa reservoir comprises the Upper Jurassic Viking Group, and the middle Jurassic Brent and Dunlin Groups. The oil column of 35-45 m and the gas column of approximately 200 m both have local variations. The reservoir is compartmentalised in seven segments, with heterogenous properties caused by alternating layers of good and poor reservoir sands, silts and shales. As a result, the porosity ranges from 10% to 27% and the permeability from hundreds of millidarcy to several darcy.

Development

The drainage strategy is managed pressure depletion with concurrent oil rim production. The field is developed with thirteen subsea wells (of which six currently are shut in), connected to five templates and directed back to a semi-submersible unit with full oil stabilisation capacities. Advanced well technology with branches and zonal control is implemented, and all wells have multiphase meters and permanent downhole gauges. Oil is exported through the Troll oil pipeline to the Mongstad terminal, and gas is exported though the FLAGS pipeline to the St. Fergus terminal. In 2017, the production plant was upgraded to handle low pressure production to boost the reserves on Gjøa. The Gjøa platform was also the first floating platform with power from shore, reducing CO_2 emissions by 200 000 tonnes per year.

Status

The current production has a relatively stable gas rate of approximately 6.3 MSm^3/d and a declining oil rate of approximately 780 Sm^3/d. Gjøa is host for the Vega, Duva and Nova fields.

The reserves estimate for Gjøa is based on the RNB2024 submitted by the operator, Neptune Energy, and includes reserves from the main field, the P1 redevelopment project, and the newly approved low low pressure (LLP) project.

Contingent resources related to the Gjøa field are discussed in Chapter 4.

OKEA's working interest on Gjøa is 12%. The other licensees are Neptune Energy Norge AS (Operator, 30%), Petoro AS (30%), and Wintershall Dea Norge AS (28%).

3.3.4. Ivar Aasen Unit (PL338 BS)

The Ivar Aasen field is located in the North Sea, 8 km north of the Edvard Grieg field and around 30 km south of Grane and Balder, c.f. Figure 5. The water depth is 110 meters. The Ivar Aasen field includes two accumulations: Ivar Aasen and West Cable. The accumulations cover several licences and have been unitised into the Ivar Aasen Unit.

Discovery

Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones.

Reservoir

The two accumulations are located on the Gudrun Terrace between the Southern Viking Graben and the Utsira High. The reservoir consists of shallow marine sandstones in the Hugin Formation and fluvial sandstones in the Sleipner and Skagerrak Formations and is of Jurassic and Triassic age. The reservoir depth is approximately 2 400 meters. The Ivar Aasen reservoir has a small overlying gas cap. The West Cable reservoir is in Sleipner fluvial sandstone of Middle Jurassic age and is located at 2 950 meters depth.

Development

The Ivar Aasen and West Cable discoveries are developed with a steel jacket platform, with living quarters and processing facilities. Drilling and completion operations are performed from a mobile jack-up rig adjacent to the Ivar Aasen platform. Water is removed from the well stream on the platform and oil and gas rates are measured before transportation through multiphase pipelines to the Edvard Grieg installation for stabilisation and export. Edvard Grieg also covered Ivar Aasen's power demand until a joint solution for power from shore was established in December 2022.

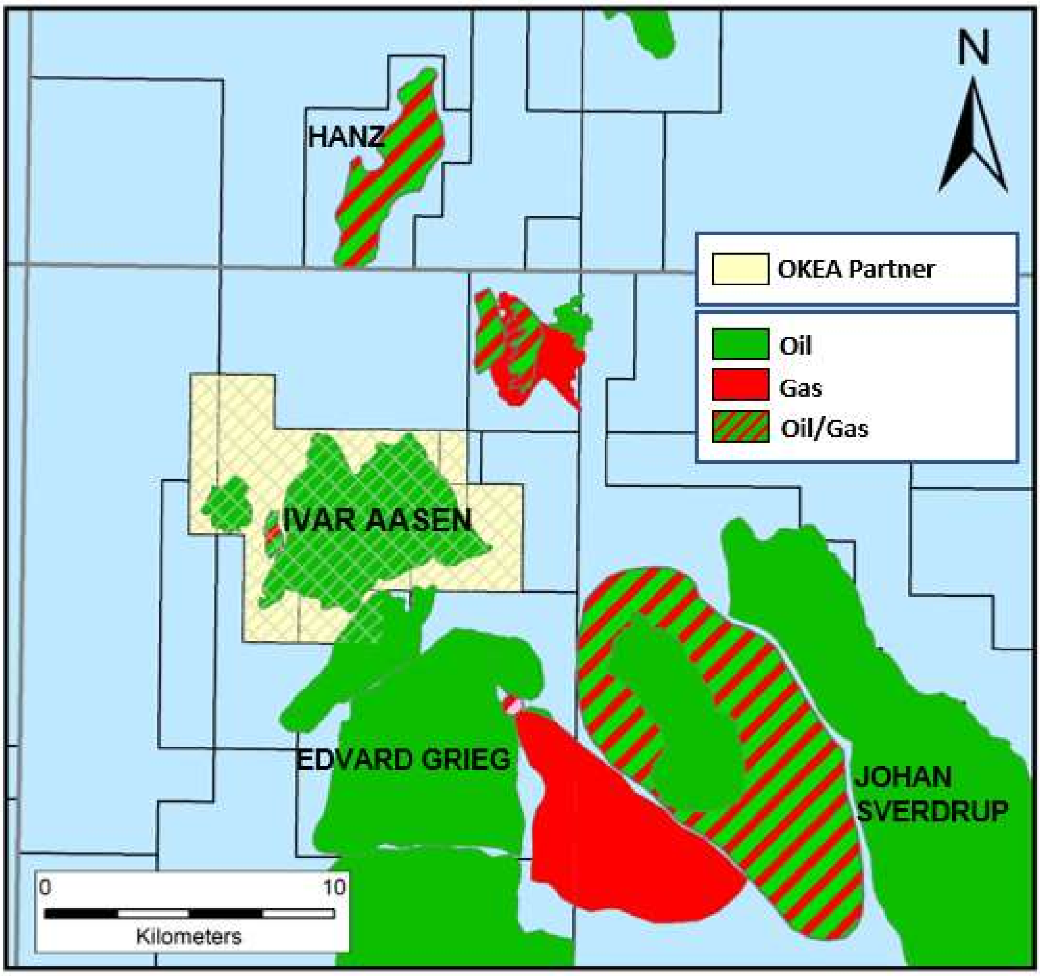

Figure 5: Ivar Aasen Unit and adjacent area (North Sea)

The drainage strategy for Ivar Aasen assumes water injection for pressure maintenance. West Cable was produced through natural pressure support where the major driving force was natural water influx and formation of a secondary gas cap.

The Ivar Aasen unit development plan (Ivar Aasen and West Cable discoveries) also includes production of the reserves from the Hanz (PL028B) discovery. The approved PDO sets out that Ivar Aasen and West Cable (Ivar Aasen Unit) will be developed in the first phase and Hanz in the second phase. OKEA has no working interest in the Hanz field.

Status

Ivar Aasen started production in December 2016. Production is on decline and the current oil production rate is approximately 25 000 bbl/d, together with some associated gas. The oil production from Ivar Aasen during 2023 was below the RNB2023 prognosis. The main cause for the production losses during 2023 relate to the short-term underperformance of the wells D-8 C and D-9 C drilled in IOR2022.

The drainage pattern in the east segment - particularly in the Skagerrak Formation - is still the main uncertainty in the reservoir.

The reserves estimate for Ivar Aasen is based on the RNB2024 submitted by the operator, Aker BP. OKEA holds a 9.2385% working interest in the unit. The other licensees are Aker BP ASA (Operator, 34.7862%), Equinor Energy AS (41.473%), Sval Energi AS (12.3173%), ABP Norway AS (1.385%) and M Vest Energy AS (0.8%).

3.3.5. Yme (PL316)

The Yme field in the Egersund Basin was discovered by Statoil in 1987 and put on production in 1996. The field is located 107 km from shore in a water depth of 93 meters, c.f. Figure 6. Nearest infrastructure is the Ula field, approximately 128 km away. After a first development, Yme ceased production in 2001 having produced 51 mmboe, as operation was deemed no longer profitable at the prevailing petroleum prices. However, there were significant volumes left in the field, and in 2007 a redevelopment plan was submitted by the new operator, Talisman. In 2013, after installation of the facilities and drilling of nine new development wells, the redevelopment project was abandoned due to structural deficiencies in the mobile offshore production unit. In 2015, the "Yme New Development" project was initiated by Repsol, and in 2018 a revised PDO was approved by the authorities.

Figure 6: Yme Gamma and Beta location map (North Sea)

Discovery

The Yme field was discovered in 1987 by the 9/2-1 well in the Gamma structure, with test oil rate of 4 145 bbl/day. In 1990, another discovery was made by the 9/2-3 well in the Beta structure, 12 km west of the Gamma structure.

Reservoir

The reservoir in Yme is the Middle Jurassic to Upper Jurassic Sandnes Fm at a depth of approximately 3 200 meters. Vertically, the reservoir is heterogeneous, and the permeability varies from millidarcy to several darcy. The sands are laterally extensive and continuous. The two main structures, Gamma and Beta, located in the Egersund basin, are each subdivided in three segments separated by faults. All these segments, except Beta West, are redeveloped.

Development

As part of the "Yme New Development", the Yme field has been developed with a jack-up mobile production unit, equipped with processing facilities. This is connected to the existing subsea tank, and oil is exported by tanker.

The field was planned to produce from 12 horizontal production wells, supported by two WAG (Water Alternating Gas) injectors and three water injectors. Produced water reinjection, in combination with a regional aquifer, will maintain the reservoir pressure and provide efficient sweep towards the producers. Production wells will be artificially lifted by gas lift.

The revised PDO was delivered in December 2017 and approved by the authorities in March 2018. The maximum plateau oil production rate was estimated to approximately 53 000 bbl/d, corresponding to the plant capacity.

Upgrade of the production unit Inspirer required more time than initially planned for, such that the hook-up date had to be postponed. Production start-up was achieved in October 2021.

Status

During 2022, early water breakthrough was observed in several production wells, leading to a reduction of the expected plateau production rate to approximately 35 000 bbl/d.

Start-up of the new Beta wells was achieved in January 2023. Start-up of the new Gamma wells was also achieved in 2023, but significantly postponed to original plans. Production by November 2023 is about 30 000 bbl/d. Currently eight producers are on stream, six in Gamma and two in the Beta reservoir.

The reserves on Yme are based on OKEA's own estimates, communicated to the market in Q3 2023. These estimates are somewhat lower than figures in the RNB2024 submitted by the operator.

OKEA holds 15% working interest in Yme. The remaining interests are held by Repsol Norge AS (Operator, 55%), PGNiG Upstream Norge AS (20%) and Lime Petroleum AS (10%).

3.3.6. Nova (PL418)

Nova lies in Block 35, license PL 418, in the northern North Sea, 17 km southwest of Gjøa, c.f. *Figure 4*. Water depth is 370 m. The field was discovered in 2012, with the well 35/9-7. The PDO was approved in 2018.

Reservoir

Intra Heather sands constitute the reservoir at Nova. These late Jurassic sands have been deposited in a turbiditic system and are eroded towards the southwest. The trap is stratigraphic with a structural component. The field can be split in 3 main areas: Main, Southeast and East, the first one being the most important one. The Intra Heather 2 Lower and Upper units constitute the main part of the reservoir. They are separated by a shale but are in communication through the faults. The Lower Unit has a 95% NTG, good connectivity and is of excellent quality. The upper Unit has a 60% NTG with a complex facies composition.

Development

The field is developed with two subsea templates: one four slot production template and one four slot template for water injection. The field is drained through pressure maintenance by water injection and gas lift. The producers are slanted to horizontal, completed with sand screens and gas lift. The production is tied back to Gjøa. The oil is exported through the Troll pipeline to the Mongstad terminal. The gas is exported though the FLAGS pipeline to the St. Fergus terminal.

Status

Production started on 29 July 2022. Initial problems with pressure support by water injection have been mitigated through drilling of a new injector W-1 AH and through additional perforations in W-2 H. However, lower-than-expected pressure support is still a limiting factor for production since the reservoir pressure needs to be kept above bubble point pressure to avoid the loss of reserves. The oil production rate is currently about 4 000 Sm^3/d, far below the initial target oil plateau rate of 7 000 Sm^3/d.

OKEA's working interest in Nova is 6%. The other licensees are Wintershall Dea Norge AS (operator, 39%), Sval Energi AS (45%), and Pandion Energy AS (10%).

3.3.7. Statfjord (PL037)

Statfjord is one of the oldest producing fields on the NCS and located in the North Sea, c.f. Figure 7.

Reservoir

The main producing intervals on the Statfjord field are the Brent (Middle Jurassic) and Statfjord (Late Triassic-Early Jurassic) Groups, with additional production from the Cook Formation in the Dunlin Group. The reservoirs of the Brent and Statfjord Groups are generally characterised by shallow marine to alluvial plain deposits of excellent quality. The Statfjord Group demonstrates more heterogeneity than the Brent Group and a higher degree of baffling.

On the Statfjord East Flank, the Brent and Statfjord reservoirs are found within a landslide complex, giving rise to increased reservoir complexity than observed in the main field.

The Cook Formation reservoir is characterised as an offshore to upper delta front and contains heterolithic sandstones with relatively high mud content/layering. Observed permeabilities are highly variable laterally and vertically, ranging from 0.001 to 1 millidarcy.

Development

In 2005 the Statfjord Late Life (SFLL) project was sanctioned. This includes partial depressurisation of the Statfjord Field to liberate and produce gas from remaining oil, and to produce the previously injected gas. The key enabler for the depressurization is an accelerated reservoir fluid offtake. Most of water and gas injection in Upper Statfjord Formation was stopped in 2007. Water and gas injection in Brent Group and Lower Statfjord Formation was stopped in the period from August (Statfjord A and Statfjord C) to November 2008 (Statfjord B). In 2011-2016, the gas production potential increased steadily with a peak in July 2016. Since then, the field gas production has generally been on decline.

In Cook Formation and in some isolated reservoir segments in the eastern part of the field water and/or gas are injected to maximize oil recovery and support producers.

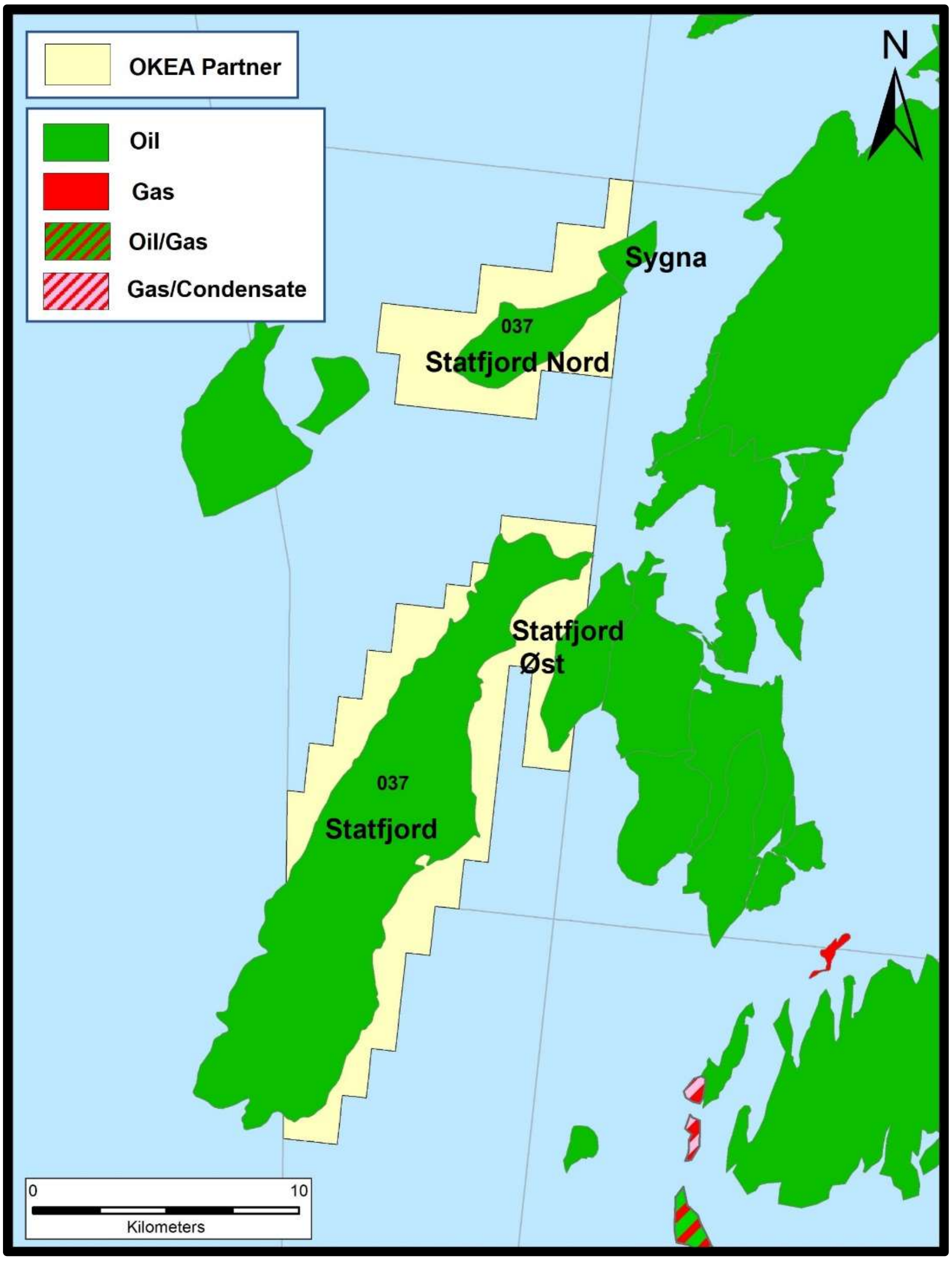

Figure 7: Statfjord area map (North Sea)

Status

In the last twelve months, 10 wells have been completed with 9 put on production. The B-15 C long horizontal frack well in Cook reservoir was drilled, but not completed in 2023. The operations will resume in mid-2024. The actual oil and gas production for 2023 came in lower than expected in RNB2023. A key focus area in next years will be to increase the offtake from Brent Group by drilling new wells to compensate for the decreasing offtake. In 2018/2019, a slowing down of the Statfjord Group de-pressurization was observed. Hence, the focus during the past two years has been to increase the offtake from the Statfjord Group. Subsequently gas production has tripled compared to the 2018/2019 level. Expected abandonment pressure for Statfjord Group is ~100-110 bar.

Reserves estimates for Statfjord are based on the operator's RNB2024, which includes only volumes related to the Norwegian part of the field. However, an economic evaluation shows that the FFE project is not commercial. Associated volumes associated to this measure are therefore treated as contingent resources.

OKEA's working interest on Statfjord is 23.93123%. The other licensees are Equinor Energy AS (operator, 40.17029%), Vår Energi ASA (21.36717%), and Equinor UK Limited (14.53131%). OKEA's working interest with respect to the Norwegian part of the Statfjord field is 28%.

3.3.8. Statfjord Nord (PL037)

Statfjord Nord (SFN) is located north of Statfjord, c.f. Figure 7.

Reservoir

Production on Statfjord Nord is from reservoirs of the Upper Jurassic Munin Formation (turbidites) and the shoreface sands of the Etive and Rannoch Formations (Brent Group), both of which exhibit excellent reservoir quality.

Development

Statfjord Nord is a subsea development with two 4-slot production templates (F and E) with 8 production wells and a single 4-slot injection template (D) with three injection wells to Statfjord Nord and one injection well to Sygna. The well stream is transferred through pipelines to the Statfjord C platform for processing, metering, and onward transportation. Water is piped from Statfjord C to the subsea injection wells.

The production strategy for Statfjord Nord is water injection targeting full voidage replacement to maintain reservoir pressure around 330 bar. The reservoir pressure lower limit for sand-free production is approximately 315 bars, and the aim is to avoid sand production.

Statfjord Nord production is constrained by the capacities of flowlines and water injection system. Given the capacities constraints, reservoir pressure is maintained at around 330 bar by balancing the reservoir fluid offtake and injecting seawater at target voidage replacement ratio of 1.

The production wells are placed high on the structure, whereas the injectors are placed in the water zone in the northern and southern parts of the field.

The dynamic model is history matched on a yearly basis. Well tests and reservoir pressure measurements are regularly carried out. Production behaviour, well productivity and reservoir pressure development are permanently monitored and analysed.

Status

Oil production in 2023 has decreased by 19% compared to prognosed, Figure 4-1 shows actual production and RNB2024 compared with RNB 2023 prognosis. The main reasons for the lower production in 2023 are:

- longer shut-in of F-1 than prognosed, need to perforate new zones to continue production
- uptime of water injection, during September 2023 the injection was down due to pigging operation and deaerator issues
- duration of turnaround SFC longer than expected

A new Etive Formation producer from the Statfjord Nord field is planned drilled from the F-4 well slot using the COSL Promoter drilling rig in Q1 2024. The scope includes P&A of existing reservoir section, followed by drilling and completion, side-tracking from the existing 9 5/8 casing.

Reserves estimates for Statfjord Nord are based on the operators RNB2024. OKEA's working interest on Statfjord Nord is 28%. The other licensees are Equinor Energy AS (operator, 17%), Petoro AS (30%), and Vår Energi ASA (25%).

3.3.9. Statfjord Øst (PL037)

The Statfjord Øst field is located northeast of the Statfjord field, c.f. Figure 7.

Reservoir

Production on Statfjord Øst is from high quality shoreface sands of the Upper to Lower Brent Group (Rannoch, Etive, Ness and Tarbert Formations).

Development

The Statfjord Øst field was originally developed with two production subsea templates (M and L) and one injection subsea template (K). Due to the pressure communication with the Statfjord field and the planned pressure blow-down (SFLL), C-33 AT4 was drilled from SFC to Statfjord Øst in 2005-2006. It uses gas for artificial lift, enabling production at low reservoir pressure. Water injection stopped in 2008 and since then Statfjord Øst has been on depletion. Current reservoir pressure on Statfjord Øst is ~170 bar, compared to ~325 bar in 2008 and 380 bar initially.

In 2016, a second well C-16 A, was drilled from SFC to Statfjord Øst, and started production in November same year. The well was shut in April 2017 due to uncontrolled sand production caused by failure of the sand control equipment in the well. An attempt to re-drill a reservoir section was made in summer 2018. P&A of the old C-16 A wellbore was performed, but the kick-off to drill the new reservoir section was not successful. A new attempt to side-track was made in spring 2019 but failed. This target location has now been included into the scope of the Statfjord Øst gas lift project.

Until the end of 2022, there were two active subsea producers M-2 BH and M-4 AH. The subsea wells did not have gas lift and hence these two wells were cyclic producers during the last several years since reservoir energy was insufficient for their permanent production.

Status

The main ongoing activity for Statfjord Øst is related to the gas lift project, which includes providing a gas lift solution for both the L- and M- subsea templates and drilling new wells capable of producing with gas lift. The authority application was approved in 2021.

The Statfjord Øst drilling campaign started in March 2023 with L-2 AH, followed by L-1 AH. Well M-2 CH was drilled and completed during the summer 2023. Finally, M-4 BH and M-1 BH were both completed by end 2023. The first gas lift project well (L-2 AH) was put in production on 20 August 2023.

Reserves estimates for Statfjord Øst are based on the operator's RNB2024. OKEA's working interest on Statfjord Øst is 14%. The other licensees are Equinor Energy AS (operator, 29.25%), Petoro AS (30%), Vår Energi ASA (20.55%), INPEX Idemitsu Norge AS (4.8%), and Wintershall Dea Norge AS (1.4%).

3.3.10. Sygna (PL037)

Sygna is located northeast of the Statfjord Nord field, c.f. Figure 7.

Reservoir

Production on Sygna is from high quality shoreface sands of the Etive and Rannoch Formations (Brent Group)

Development

Sygna is developed with subsea installations with production and injection wells. The producers are on the N-template (N-1 H, N-2 AH, and N-3 H). There is one available slot on the template. Water is injected from the D-template through well D-3 H. The D-template itself is installed on the neighbouring Statfjord Nord field. The well stream is transferred through pipelines to the Statfjord C platform for processing, metering and onward transportation. Water for reservoir pressure maintenance is pumped through a pipeline from Statfjord C.
The production strategy for Sygna is full voidage replacement maintaining the reservoir pressure around 330 bar. The reservoir pressure lower limit for sand-free production is approximately 315 bar, and the aim is to avoid sand production. For the most part, there is a continuous water injection into reservoir through the injector, whereas the three production wells are producing alternately, favouring the wells with the lowest water cut.

The production wells on Sygna are placed high on structure, whereas the water injector is located low on structure in the western part of the field.

To map the undrained areas, reduce the risk concerning future IOR targets and for better understanding of the flow pattern and structural model of the field, a 4D seismic survey was conducted in 2011 covering the area of the Statfjord Nord and Sygna fields.

Well tests and reservoir pressure measurements are regularly carried out. Production behaviour, well productivity and reservoir pressure development are permanently monitored and analysed.

Status

There have not been drilled any new wells in the last 12 months. A light well intervention was performed in autumn 2023 to repair the downhole safety valve on N-2 H.

Reserves estimates for Sygna are based on the operator's RNB2024. OKEA's working interest on Sygna is 15.4%. The other licensees are Equinor Energy AS (operator, 28.025%), Petoro AS (30%), Vår Energi ASA (20.995%), INPEX Idemitsu Norge AS (4.32%), and Wintershall Dea Norge AS (1.26%).

4 Contingent resources

Contingent resources are potentially recoverable volumes from proven accumulations, which are not currently considered commercially viable. This essentially includes projects that are being matured but that have not passed a Final Investment Decision (FID).

4.1. TOTAL CONTINGENT RESOURCES ESTIMATES

OKEA holds contingent resources in several licenses, as shown in *Table 4*. The contingent resources are verified by a third-party certification performed by AGR Petroleum Services.

Table 4: OKEA contingent resources as of 31 December 2023

Discovery – Project	OKEA WI	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
		1C/P90	2C/P50	3C/P10	1C/P90	2C/P50	3C/P10
Aurora	**65 %**	**10.16**	**12.98**	**19.27**	**6.60**	**8.44**	**12.53**
Brage	**35.2 %**	**19.54**	**41.12**	**64.89**	**6.88**	**14.47**	**22.84**
Brasse	**39.2788 %**	**19.35**	**27.64**	**33.94**	**7.60**	**10.86**	**13.33**
Calypso	**30 %**	**11.37**	**15.15**	**18.94**	**3.41**	**4.55**	**5.68**
Draugen	**44.56 %**	**7.74**	**13.53**	**18.43**	**3.45**	**6.03**	**8.21**
Gjøa	**12 %**	**11.83**	**21.28**	**28.45**	**1.42**	**2.55**	**3.41**
Ivar Aasen	**9.239 %**	**7.39**	**14.77**	**23.79**	**0.68**	**1.36**	**2.20**
Nova	**6 %**	**21.28**	**33.21**	**49.64**	**1.28**	**1.99**	**2.98**
Statfjord	**28 %**	**23.83**	**41.34**	**58.84**	**6.67**	**11.57**	**16.48**
Statfjord Nord	**28 %**	**3.25**	**5.59**	**7.93**	**0.91**	**1.57**	**2.22**
Statfjord Øst	**14 %**	-	-	-	-	-	-
Sygna	**15.4 %**	-	-	-	-	-	-
Yme	**15 %**	**2.30**	**8.30**	**9.55**	**0.35**	**1.25**	**1.43**
Total Contingent Volumes					**39.2**	**64.6**	**91.3**

Please note that totals in the table above are arithmetic and not stochastic summations. The aggregate Low (1C) may be a very conservative estimate and aggregate High (3C) may be a very optimistic one. Aggregates of Base (2C) results typically have less portfolio effect.

4.2. Description of contingent resources

The following section describes fields/discoveries with contingent resources where OKEA holds a working interest.

4.2.1. Brasse (PL740)

The Brasse discovery is located in the PL740 license, in Block 31/7, approximately 13 km south of the Brage field and 13 km east of the Oseberg field, c.f. Figure 3. Discovered in June 2016 by well 31/7-1, the field consists of a low relief, three-way dip-closed structure with a stratigraphic pinch-out component to the north. The structure has been penetrated by six wellbores in total.

OKEA became partner and operator of the license in 2023. OKEA's working interest in the Brasse discovery is 39.2788%. The other licensees are DNO Norge AS (50%), Lime Petroleum AS (6.2788%), and M Vest Energy AS (4.4424%).

Reservoir

The main reservoir interval in the discovery is represented by the Sognefjord Formation (Upper Jurassic) with a gross hydrocarbon column of approximately 45 m, consisting of approximately 22 m of oil (36 °API) with a gas cap. The oil-water contact in the central and southern areas of the field is located at approximately 2172.5 mTVDSS, with the gas-oil contact varying between 2148 mTVDSS (observed in well 31/7-1) and 2155 mTVDSS (observed in well 31/7-2 A). Well 31/7-3 A, drilled in the northern area of the discovery, encountered three oil-filled intervals, where the two deepest intervals had different oils (34°API) compared to the main area in the south. The two deeper sand intervals have been interpreted as smaller local closures separated from the main area.

The reservoir was found to be depleted by ca. 20 bar compared to the expected hydrostatic pressure. This pressure depletion, observed in all six wells drilled in Brasse, is considered to be caused by production from the giant Troll field, located ca. 35 km northeast of Brasse, and connected to Brasse via a massive regional aquifer.

Development

The discovery is planned to be developed by two horizontal wells (one optional dual-lateral), completed with screens for sand control and placed within a two-slot subsea template. According to current plans, the discovery will be tied back to the Brage platform with a 10" PiP flowline, an umbilical and a pipeline for gas-lift. Topside Brage, a J-tube extension and an inlet arrangement to Brage production manifold is required, in addition to a new, common gas-lift/export cooler at Brage.

Status

DG2 approval was achieved in August 2023. DG3 and PDO submission is planned for Q1 2024.

4.2.2. Aurora (PL195)

The Aurora discovery is situated in licenses PL195 and PL195 B, approximately 20 km west of Gjøa, c.f. *Figure 4*. The water depth in the area is about 373 m. OKEA became operator of the two licenses in October 2020 and holds a 65% working interest in each. The other partner is Petoro AS (35%).

Discovery

Aurora was discovered in 1988 through well 35/8-3. The well proved hydrocarbons in the Intra-Heather Formation sandstones. No gas-water contact was apparent, indicating gas down to 3 511 m TVDSS.

The discovery was appraised by well 35/8-4, which encountered no hydrocarbons, indicating water up to 3 611 m TVDSS. Seismic data suggests a major fault east of the discovery well. Consequently, any hydrocarbons east of this fault are considered prospective volumes.

Reservoir

Log analyses of the Heather sands indicated a probable gross gas column of 70 m with a net pay of 31.9 m. Average porosity in the net sand was 15.6% with an estimated average water saturation of 22%. Reservoir temperature is about 90 degree Celsius, and pressure is around 400 bar. No fluid samples were taken.

Development

OKEA has initiated a project regarding development of the Aurora discovery as a tie-in to Gjøa. Currently, the discovery is envisioned to be produced by means of a single gas producer well, possibly deviated, using pressure depletion as major driving mechanism. Tie-back to Gjøa can be accomplished by utilizing existing infrastructure in the area, related to the Vega, Nova and/or Gjøa developments.

Status

The development project was initiated in September 2020 and is currently working towards a decision to drill an appraisal well in 2025. First gas from Aurora could then be produced in 2028, given a positive outcome of the appraisal well and available capacity at Gjøa.

4.2.3. Calypso (PL938)

The Calypso gas and oil discovery is located in license PL938, approximately 12km northwest of the Draugen Field, c.f. *Figure 2*. Neptune Energy Norge AS is the operator with a 30% interest. Partners are OKEA (30%), Pandion (20%) and Vår Energi (20%).

Discovery

Calypso was discovered in November 2022 with the 6407/8-8 S exploration well. The well encountered an estimated 8 m thick gas column and a 33 m thick oil column in a 132 m thick Garn Formation.

Reservoir

The reservoir is of good to very good quality, with average permeability ranging from 100-1000 millidarcy and porosity averaging around 21%. The OWC is interpreted from pressure points and a total column from the oil-water contact to the crest of the structure is 41 m. The pressure is close to hydrostatic.

Development

The discovery is likely to be developed with one multilateral well with potentially one water injector as drive mechanism. Aquifer strength is currently being evaluated to better understand the need for water injection. A tie-back to Draugen may be achieved with pressure depletion as the main driving mechanism (depending on aquifer study outcome). The operator also considers Njord (via Hyme) as an alternative host.

Status

The development project was initiated in August 2023 and is currently working towards a DG1.

4.2.4. Draugen IOR

The Draugen asset is described in section 3.3.1.

During 2020 and 2021, the infill well target Garn West Sør close to the existing producer well D-2 H was identified. During summer 2023, two observation wells were drilled to this target, and the nearby Springmus target. Both wells proved oil at these locations. Detailed re-modelling of the two accumulations is ongoing.

The potential for increased injection by restoring PWRI to the Northern water injection template (NWIT) was investigated by injection at a high rate in the NWIT wells B-2 and B-5 the winter 2022-2023. The test revealed a significant potential for IOR and additionally providing for re-injection of all produced water. The onset of injection is depending on an electrification of the Draugen platform facilities.

4.2.5. Brage IOR

The Brage asset is described in section 3.3.2. Main method for increased recovery on the Brage Field is through infill drilling. Infill drilling for increasing the recovery is the main strategy for the future too, but also other methods for increased recovery are being evaluated.

For 2024, there are four wells on the drilling schedule which are currently being matured. A production well A-21 A in Talisker South which includes a pilot hole into Brent Ardbeg, a production well A-28 C in Fensfjord Bowmore with back-up target in Bowmore Sognefjord, an appraisal well in Sognefjord East (A-13 D Sognefjord East discovery in 2023) and a production well A-5 A in Talisker West. Also, a water injection well to support the Talisker producers is currently being drilled (Nov. 2023) where the injection is expected to start in Dec. 2023 / Jan. 2024. In addition to the infill/development wells described above, a test production of Shetland Fm. will be performed through an intervention in well A-31 T2 in 2024. Based on the results from this test production, the potential in Shetland will be evaluated.

4.2.6. Gjøa IOR

The Gjøa asset is described in section 3.3.3. The operator reports in RNB2024 contingent volumes related to gas cap blowdown in the P4 segment, as well as oil well interventions.

4.2.7. Hamlet

The Hamlet discovery was proven in spring 2022 by Neptune and is located in the licenses PL153 (Gjøa) and PL153 C.

Reservoir

The Hamlet discovery is composed of stacked turbiditic sands from the Agat Fm. Two main sands are identified from seismic and well observations with permeabilities between 10 and 400 millydarcy.

Development

The planned drainage strategy is managed pressure depletion with two producer wells. The well flow would be brought back to Gjøa via the G template (P1 segment). An investment decision was attempted ("Gjøa Nord project"), but not obtained in December 2022. The license is now evaluating the possibility to develop Hamlet together with the Ofelia discovery, made in 2022 in the neighbouring license, north of Hamlet.

4.2.8. Ivar Aasen IOR

The Ivar Aasen asset is described in section 3.3.4. Several infill drilling opportunities have been identified on Ivar Aasen and are currently in various stages of maturation. During 2023, the IOR2024 campaign went through two rounds of target maturations, but no alignment in the license was obtained for the targets. As a result, the IOR 2024 was eventually cancelled. Work is ongoing to mature a IOR2026 campaign, with the building of new reservoir models and analytical approaches. The gas blowdown on Ivar Aasen has been identified as a late life opportunity, and maturation will continue in line with an update of the drainage strategy.

4.2.9. Yme IOR

The Yme asset is described in section 3.3.5. The operator reports in RNB2024 contingent resources related to possible infill drilling. These volumes are included in the ASR.

4.2.10. Nova IOR

The Nova asset is described in section 3.3.6. The operator reports in RNB2024 contingent resources related to low pressure production and infill drilling. These volumes are included in the ASR.

4.2.11. Statfjord IOR

The Statfjord asset is described in section 3.3.7. The operator reports in RNB2024 contingent resources related to a variety of IOR measures, including infill drilling, recompletions and modifications. These volumes are included in the ASR.

4.2.12. Statfjord Nord IOR

The Statfjord Nord asset is described in section 3.3.8. The operator reports in RNB2024 contingent resources related to one infill producer in 2026 and interventions in 2 injectors. These volumes are included in the ASR.

5 Management discussion and analysis

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields on the basis of expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves is set at zero cash flow. The company has used a long-term inflation assumption of 2%, a long-term exchange rate of USDNOK 9.0, and a long-term oil price of 72 USD/bbl (real 2023 terms).

The calculations of recoverable volumes are however associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 figures reflect our high confidence estimates. 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. Thus, there is a risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the economical reserves. Low oil prices may force the licensees to shut down producing fields early and lead to lower production. Similarly, better-than-expected reservoir performance or higher oil prices may extend the lifetime of the fields beyond what is currently premised.

Svein J. Liknes

CEO

OKEA ASA is a leading mid- to late-life operator on the Norwegian continental shelf (NCS).

OKEA finds value where others divest and has an ambitious strategy built on growth, value creation and capital discipline.

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