Annual statement of reserves and resources

OKEA ASA – 2022

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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 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 2022, with cut-off date 31 December 2022.

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 the 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.

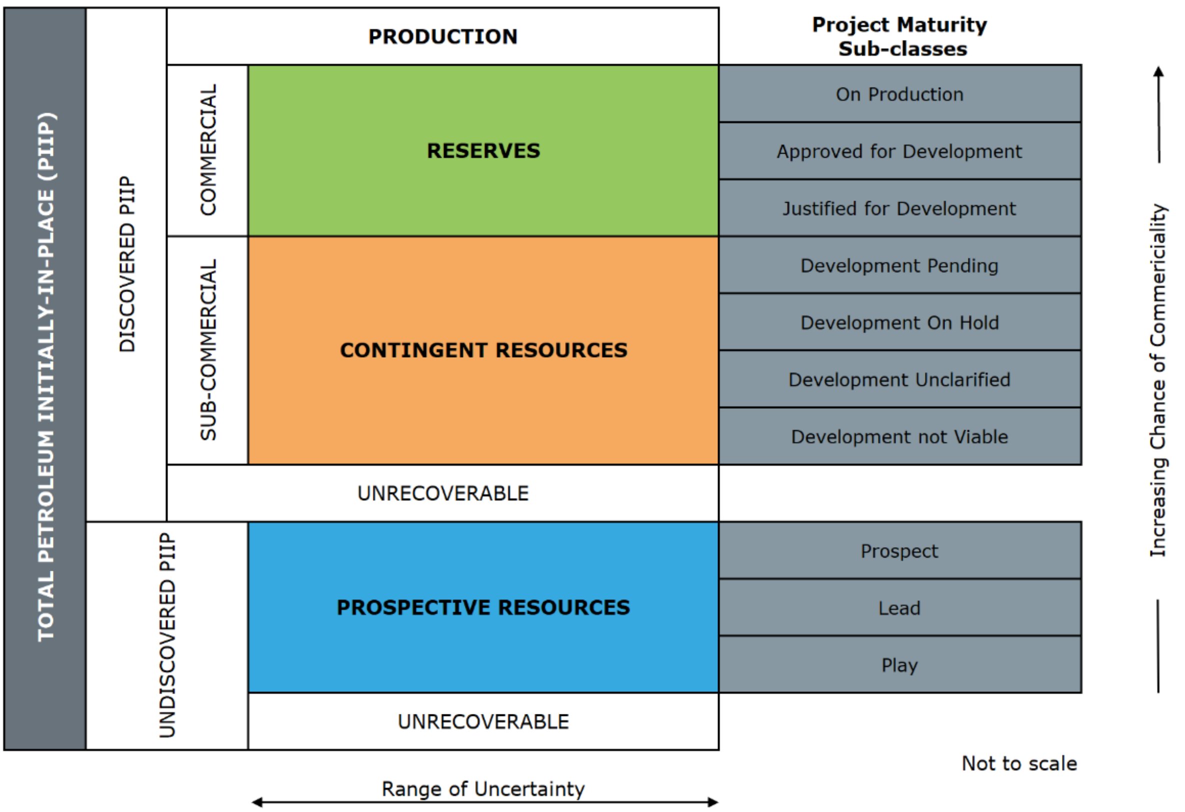

Figure 1: PRMS including sub-classes based on maturity

3 Reserves

OKEA ASA ("OKEA") has reserves distributed across six 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 Petroleum and Energy or an exemption from this has been given.

Table 1: OKEA asset portfolio with reserves as of 31 December 2022

Field/Project	OKEA Working Interest	Operator	Project Status Category	Comment
Draugen field	44.56 %	OKEA ASA	On production	Includes Hasselmus discovery
Brage unit	35.2 %	OKEA ASA	On production	New in OKEA portfolio
Gjøa field	12 %	Neptune Energy Norge AS	On production	Includes P1 redevelopment
Ivar Aasen unit	9.2385 %	Aker BP ASA	On production	Increased WI since ASR EoY 2021
Yme field	15 %	Repsol Norge AS	On production	
Nova field	6 %	Wintershall Dea Norge AS	On production	New in OKEA portfolio

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 68 USD/bbl, with a long-term currency rate of NOKUSD 9.0. Gas price and NGL prices are set to 3.07 NOK/Sm^3 and 485 USD/ton, respectively. All prices are in real 2022 and a 2% annual inflation rate is used.

Note that the gas reserves are reported as sales gas, given the actual Gross Calorific Value (GCV), and not converted to 40 MJ/Sm^3.

In addition, the following conversion factors are used:

Oil - 1 Sm^3 = 1 Sm3 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 2022 are estimated at 45.5 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 60.2 million barrels of oil equivalents. The reserves figures account for the effects of production in 2022. The split between oil, NGL and gas, and between individual assets is given in *Table 2*.

Table 2: OKEA Reserves as of 31 December 2022 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									
Draugen	44.56 %	38.03			**16.95**	41.92			**18.68**
Gjøa	12 %	1.01	4.72	16.45	**2.66**	2.35	8.60	30.03	**4.92**
Ivar Aasen	9.2385 %	37.32	2.12	6.62	**4.26**	50.36	3.30	10.30	**5.91**
Brage	35.2 %	4.59	0.59	1.34	**2.29**	4.93	0.85	1.94	**2.72**
Nova	6 %	45.47	5.77	9.60	**3.65**	71.05	7.68	12.63	**5.48**
Yme	15 %	24.86			**3.73**	54.77			**8.22**
Total Net					**33.54**				**45.92**
Reserves – Approved for Development									
Draugen - Restart of gas export	44.56 %		1.21		**0.54**		1.32		**0.59**
Draugen - Subsea Pump upgrade	44.56 %	3.64	0.16		**1.69**	4.36	0.19		**2.03**
Draugen - Hasselmus	44.56 %		0.39	6.18	**2.93**		0.42	8.32	**3.89**
Brage - Talisker East	35.2 %	1.29	0.18	0.41	**0.66**	2.09	0.29	0.66	**1.07**
Total Net					**5.82**				**7.58**
Reserves – Justified for Development									
Draugen - Power from Shore	44.56 %		0.30	2.77	**1.37**		0.33	3.08	**1.52**
Draugen - lifetime to 2040	44.56 %	9.90	0.44	0.45	**4.80**	10.61	0.47	0.48	**5.15**
Total Net					**6.17**				**6.66**
Reserves –Total									
Total Net					**45.53**				**60.16**

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 69.4 mmboe. For comparison, the corresponding Total Net 1P-, 2P- and 3P-reserves in ASR 2021 (31 December 2021) were 35.8, 46.6 and 56.8 mmboe, respectively, c.f. *Table 3*.

For Brage, an economic cut-off at end of year 2025 results in significantly lower reserves than those in the corresponding RNB-profile due to the fact that several infill well projects are classified as contingent resources, see section 4.2.2. However, the license has agreed that a principle of "continuous infill drilling for as long as possible" shall be applied to maximize recovery from the field. This is reflected in the license budget through the fact that corresponding drilling costs in 2023 are included as a firm cost. If these volumes were included, economic cut-off for the Brage asset would occur at end of year 2030.

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 2021 (31 December 2021).

Table 3: OKEA Reserves Development from 31 December 2021 to 31 December 2022 in mmboe

Reserves Development												
Asset	EoY 2021		Production		Acquisitions/Disposals		Revisions of previous estimates		Projects matured		EoY 2022	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Draugen	**22.00**	**27.94**	-2.39	-2.39			0.73	-2.48	7.94	8.78	**28.28**	**31.85**
Brage	**-**	**-**	-0.16	-0.16	3.12	3.95					**2.96**	**3.79**
Gjøa	**4.67**	**7.54**	-2.52	-2.52			0.52	-0.10			**2.66**	**4.92**
Ivar Aasen	**0.32**	**0.41**	-0.38	-0.38	4.31	5.87	-0.03	-0.06	0.03	0.06	**4.26**	**5.91**
Yme	**8.85**	**10.72**	-0.54	-0.54			-4.57	-1.96			**3.73**	**8.22**
Nova	**-**	**-**	-0.05	-0.05	3.70	5.54					**3.65**	**5.48**
Total	**35.84**	**46.61**	-6.05	-6.05	11.13	15.35	-3.36	-4.59	7.97	8.84	**45.53**	**60.16**

"Acquisitions" are related to acquisitions of working interests in Brage, Nova and Ivar Aasen in 2022.

"Production" is primarily related to the Draugen and Gjøa assets. For Brage, Nova and Ivar Aasen, production is counted from the effective day of the relevant transitions, only.

The significant increase in Draugen reserves is related to maturation of the Power from Shore project (including a lifetime extension to 2040) and the subsea pump upgrade.

The loss of reserves on Yme from a revision of previous estimates is primarily related to early water breakthrough in existing producers.

For some assets, 1P volumes are reduced as result of earlier economic cut-off.

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 through 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 are gas lifted, 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 16 000 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.

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) is injecting condensate that cannot be exported while gas is imported for fuel. 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 RNB2023 submission by OKEA, assuming production until economic field lifetime at end of 2040. Note that the lifetime of the field has been extended as consequence of the Power from shore project, see 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%).

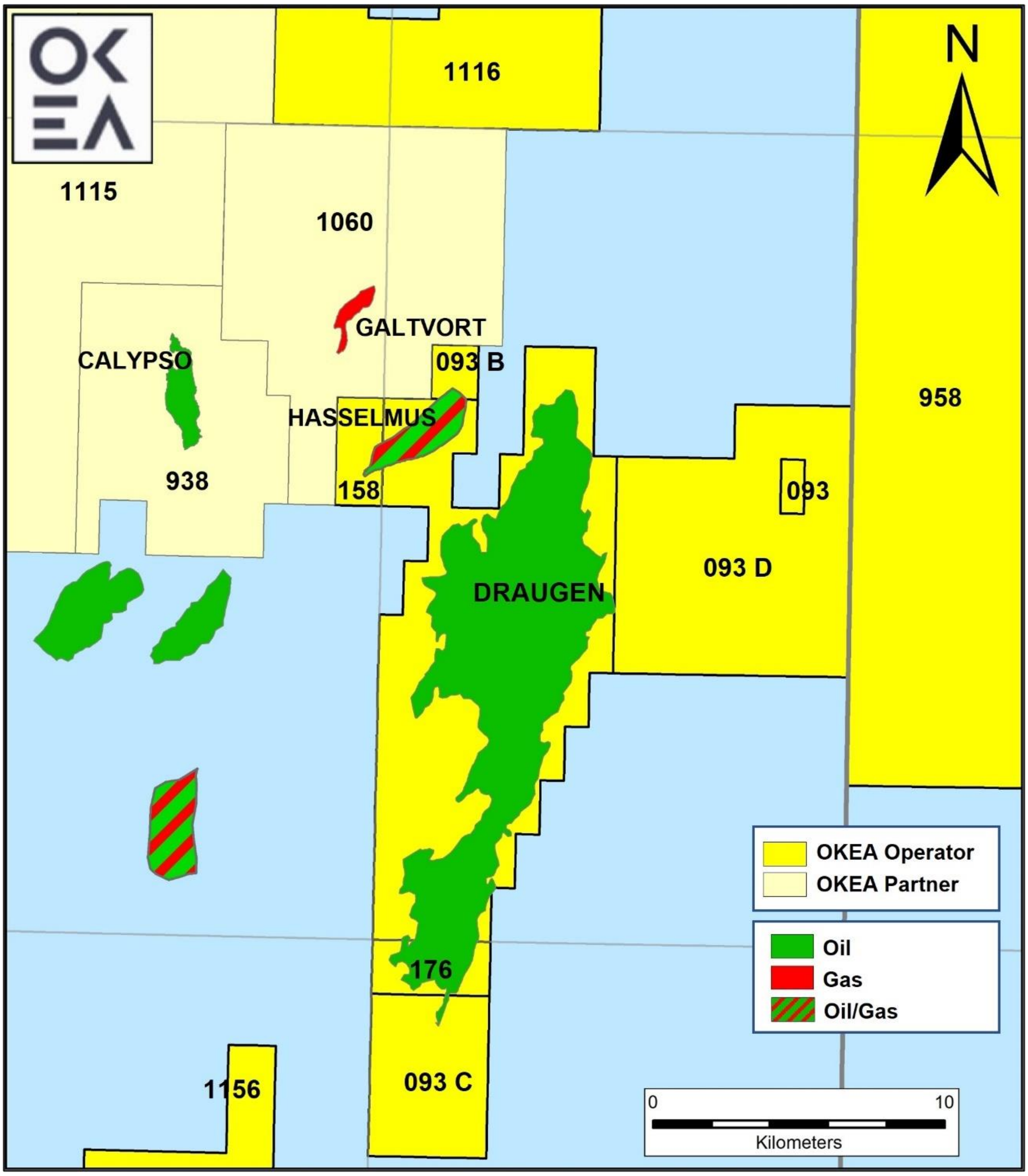

Figure 2: Draugen field location and adjacent area (Norwegian Sea)

Hasselmus

Hasselmus is a gas discovery with a 5.5 meters thin 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. Average permeability is estimated to be approximately 300 mD over the gas bearing interval. Seismic interpretation indicates that the reservoir is not affected by any major faults.

The drainage strategy for the Hasselmus development will involve 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.

The development will be a tie-back to the Draugen field with 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.

The Hasselmus development project passed FID in May 2021 and is currently in the execution phase. Associated export volumes are therefore reported as reserves.

Drilling of the production well 6407/9-H-1 H was carried out during the summer 2022, the well encountered reservoir in close agreement with the prognosis.

The subsea and topside installations and modifications are planned for mid-2023. First gas is expected in Q4 2023.

Restart of Gas Export

The Hasselmus development, will provide sufficient gas to meet Draugen's fuel consumption requirement and thereby allow for restart of gas export from Draugen. Expected NGL volumes produced from the Draugen field that can be evacuated through the Åsgard transport system after Hasselmus start-up are therefore reported as reserves.

Subsea Pump Upgrade

The subsea pump upgrade project was sanctioned by the license summer 2022 and the incremental increase in production is accordingly reported as reserves.

The upgrade is to increase Draugen production through

- improving production potential by lower pump suction pressure
- removing integrity issue and restore simultaneous operation of two pumps
- building late life IOR capability on Draugen

Power from Shore

The project "*Haltenbanken 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. This measure will not only reduce emissions from the two platforms drastically, but also result in reduced OPEX and higher gas export from Draugen.

Lifetime to 2040

A direct consequence of the PfS-project being sanctioned is that 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*.

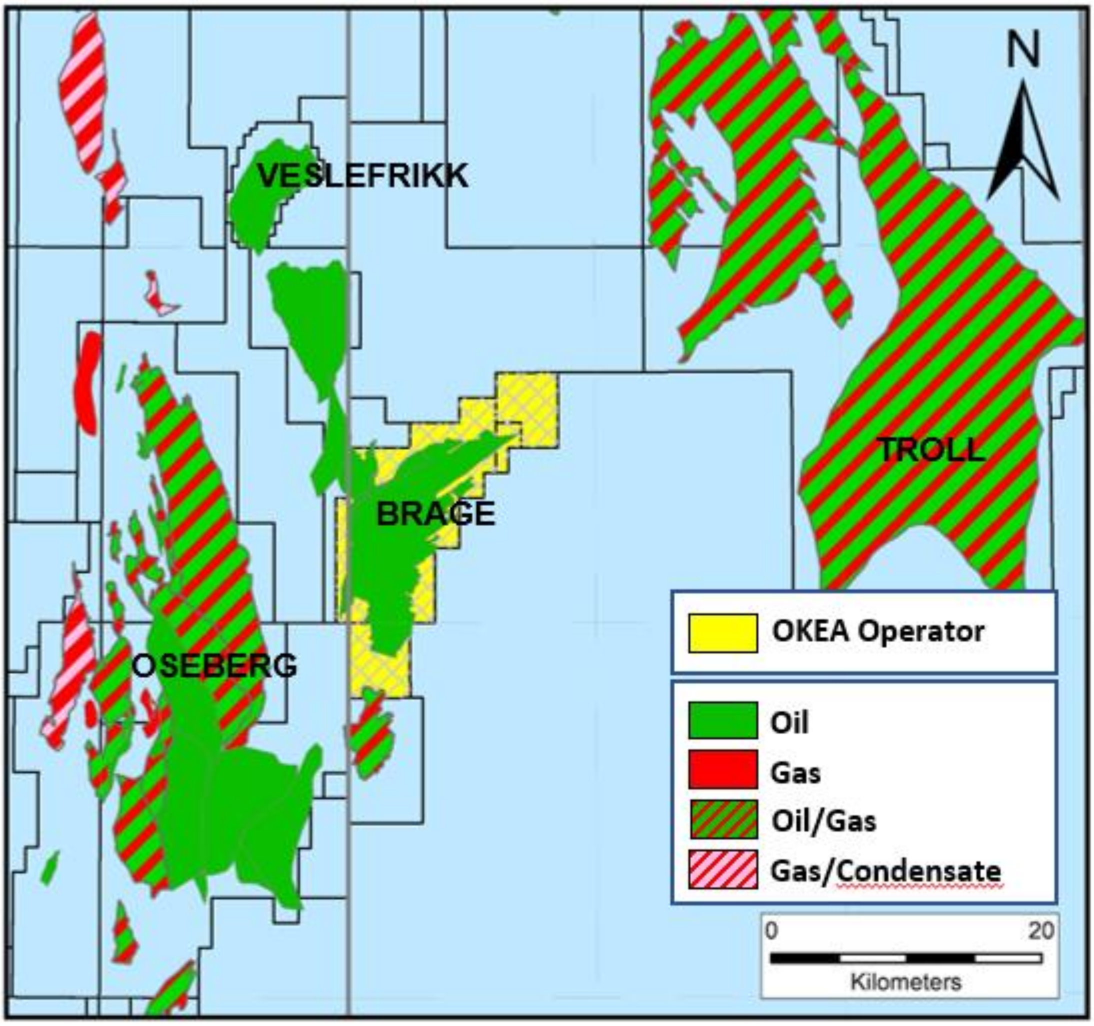

Figure 3: Location of the Brage Unit and adjacent area (North Sea)

Discovery

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

Reservoir

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

Development

Brage is a field in the northern part of the North Sea, ten kilometres 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.

The Brage field (Figure 5) is currently producing from four 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 oil in the Statfjord formation is highly undersaturated and has a bubble point pressure of ~100 bar and solution GOR of ~55 Scm/Scm. The reservoir is produced above bubble point pressure and has not been below this pressure historically. Good internal connectivity is observed in Statfjord. Ten production wells and three injection wells are currently in operation in Statfjord. Both, produced water and Utsira water, is used for water injection in Statfjord. A new Statfjord well (A-32 C) was drilled in 2022. A new infill target in the northern part of Statfjord in combination with development of Cook fm is under maturation for infill drilling in 2023.

In contrast to the Statfjord formation, the shallow marine Fensfjord formation consists of poorer property sands and internal flow barriers. Seven production wells are currently in operation, and pressure support is mainly provided by the aquifer. Utsira water is occasionally injected in the only remaining injection well when injectors in other reservoirs are unavailable and there is excess water. The GOR in the Fensfjord wells varies due to heterogeneity in the reservoir. The Fensfjord wells produce at varying GOR between 75 and 800 Scm/Scm. Historically production has been below bubble point pressure, and gas was injected in the reservoir during the first years of operation. A new well was drilled in Fensfjord in 2022, but not completed due to low oil saturation (target area was drained). A new Fensfjord well (A-13 D) in the Southern part of Fensfjord will be drilled in 2023.

The Draupne/Sognefjord reservoir was initially produced by primary depletion from three production wells, until March 2009. The wells produce at a GOR of between 800-2500 Scm/Scm. Since 2019 three new producers have been drilled and put on production: A-15 A (2019), A-36 B (2021) and A-35 B (2022). During 2022 a new gas producer to the crest of the Draupne/Sognefjord structure has been matured for infill drilling in 2023.

In the Brent reservoir, production by pressure depletion started in the Bowmore segment in February 2008, and production from the Knockando segment started in December 2008. In 2009, a water injector was drilled to provide pressure support and sweep to the Bowmore segment.

The 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

Status

The current production on Brage is in the order of 6 300 bbl of oil and 240 000 bbl of water per day. 122 000 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 22 producers and 4 injectors. Production is continuously monitored and optimised by a production management team.

The reserves estimates are based on the RNB2023 submission by the former operator Wintershall Dea, assuming production until technical field lifetime at end of 2030.

As of 31 December 2022, 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 licence, c.f. *Figure 4*. Water depth in the area is 360 meters.

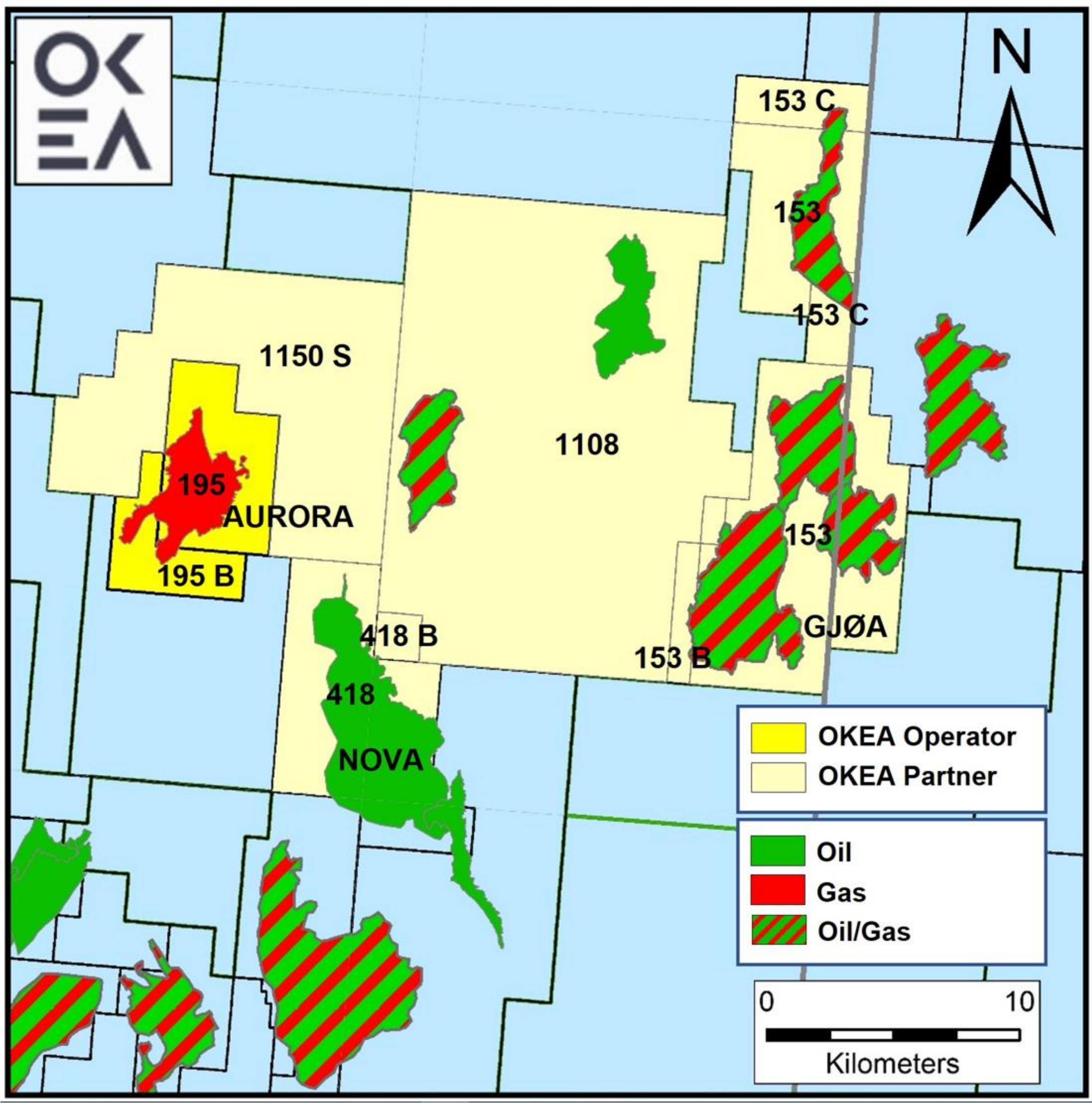

Figure 4: Gjøa field location and adjacent area (North Sea)

Discovery

The field was discovered by exploration well 35/9-1 / 35/9-1 R in 1989, confirming gas in the Viking and Brent groups, 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 35-45m and the gas column of approximately 200m 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 milli-Darcy 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 7 000 MSm^3/d and a declining oil rate of approximately 1 000 Sm3/d. There are two oil producers, G-4 and B-3 and five gas producers.

Gjøa is already host for the Vega field, became host for Duva in August 2021, and host for Nova in July 2022.

The reserves estimate for Gjøa is based on the RNB2023 submitted by the operator, Neptune Energy, and includes reserves from the main field and reserves related to the P1 redevelopment project. The reserves are increased due to a planned restart of the well B-1 in 2024 and a longer production life for the P-1 wells. The ratio between NGL and dry gas has changed due to changes done at St Fergus.

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 of 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. Note that OKEAs working interest has increased from 0.554% to 9.239% since ASR 2022.

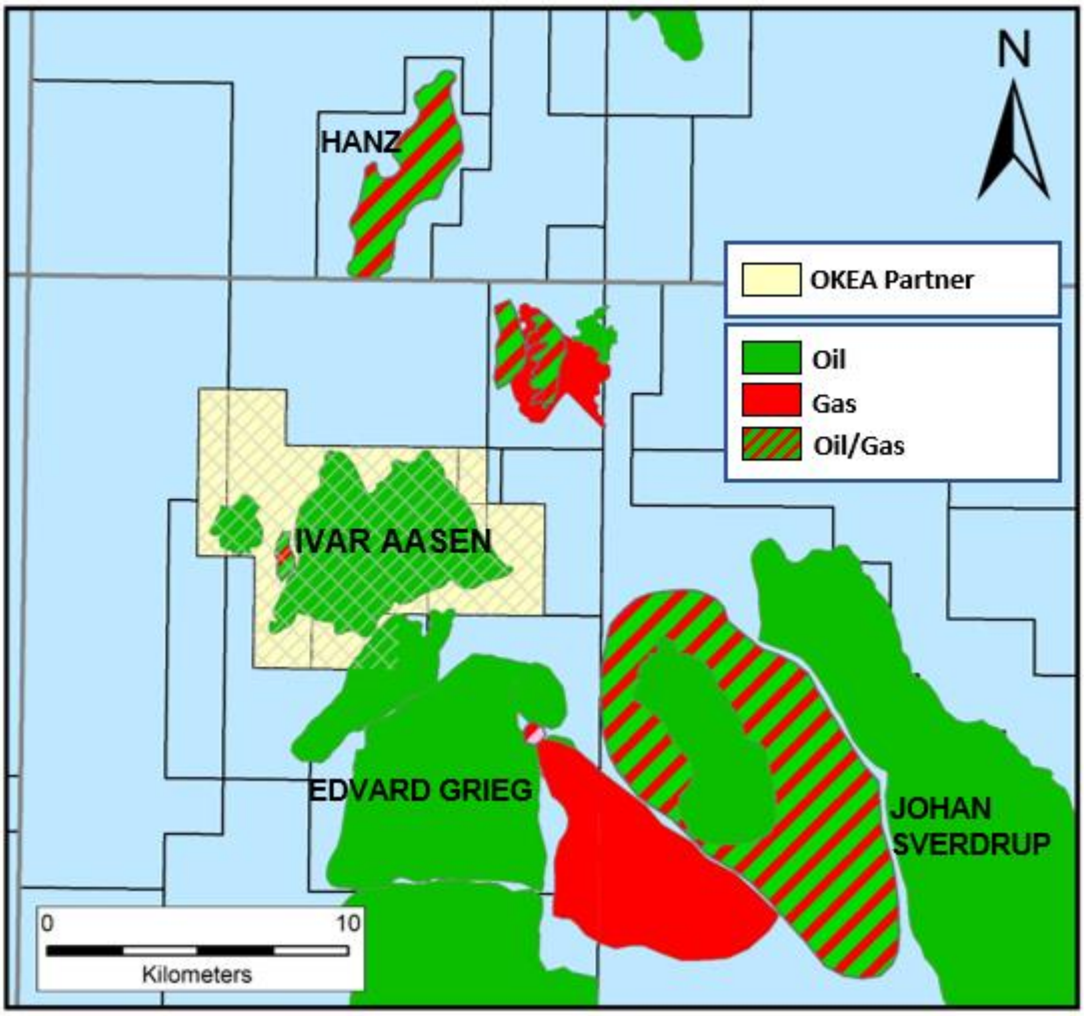

Figure 5: Ivar Aasen Unit and adjacent area (North Sea)

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 power demand until a joint solution for power from shore was established in December 2022.

The drainage strategy for Ivar Aasen assumes water injection for pressure maintenance. West Cable will be produced through natural pressure support where the major driving force will be 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 ownership interest in the Hanz field.

Status

Ivar Aasen started production in December 2016. Production is on decline and the current oil production is approximately 30 000 bbl/d, together with some associated gas. The oil production from Ivar Aasen during 2022 was below the RNB2022 prognosis. The main cause for the production losses during 2022 relate to operational challenges at Edvard Grieg.

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

Three new wells, two combined producer/injectors (D-8 D and D-9 C) and one producer (D-13 B), are currently being drilled during the IOR 2022 campaign.

The reserves estimate for Ivar Aasen is based on the RNB2023 submitted by the operator, Aker BP. As of 31 December 2022, 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.

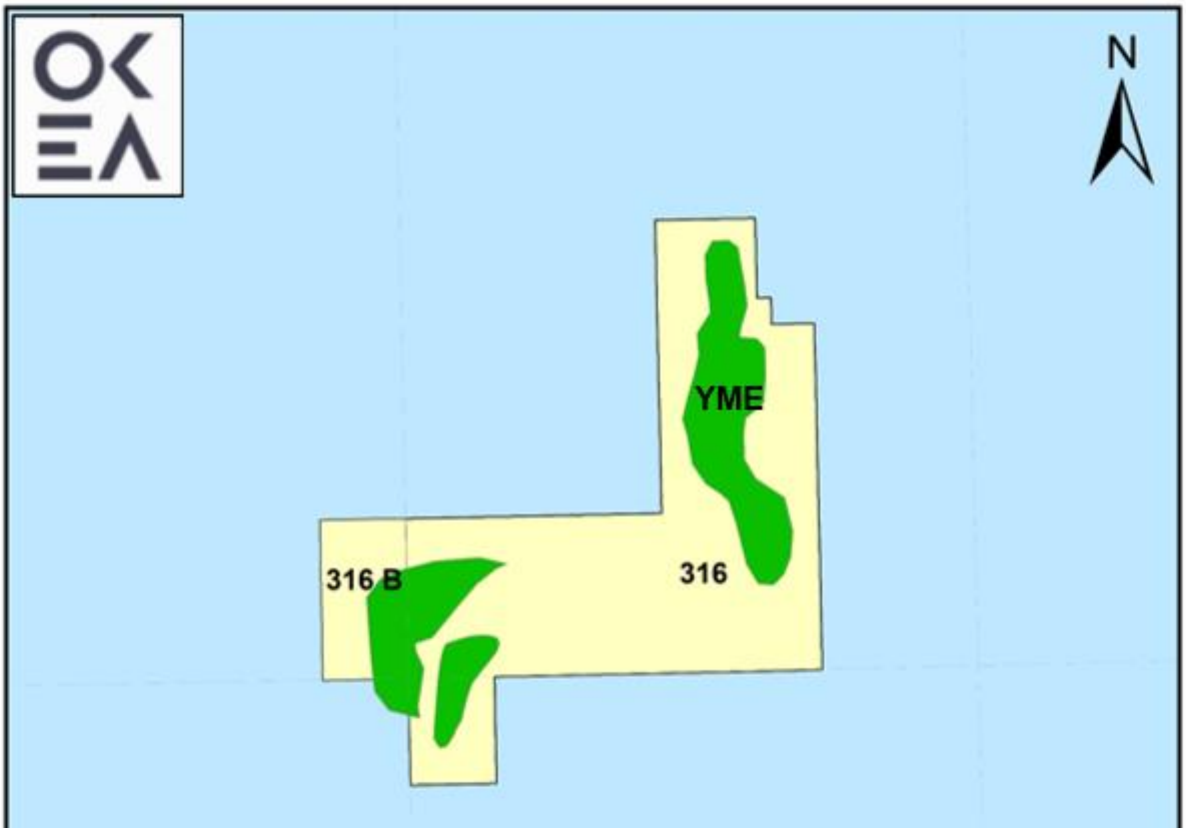

Figure 6: Yme Gamma and Beta location map (North Sea)

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 oil. In 1990, oil 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 milli-Darcy 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, will be redeveloped.

Development

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

The field will 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.

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.

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.

Status

During 2022, water breakthrough was observed in several production wells, leading to a reduction of the expected plateau production rate to approximately 35 000 bbl/d. As result of several topside issues, plant regularity was significantly lower in 2022 than expected.

Drilling of new Beta wells was achieved in 2022, as planned. However, drilling operations on the new Gamma wells was postponed to 2023, due to both the need for additional recompletion of Gamma wells and the abovementioned topside issues.

The reserves on Yme are based on RNB2023 as submitted by the operator and were significantly reduced in 2022.

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

3.3.6. Nova (PL418)

Nova lies in Block 35, licence 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 three slot production template and one three 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 a 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. The injection is started. The field is currently ramping up with a target oil plateau rate of 7 000 Sm3/d in 2023. This rate was, however, not achieved in 2022: Integrity issues with two producer wells required these well to be shut-in, waiting for LWI. In addition, lack of pressure communication of water injection well W-1 H required to reduce production to avoid reserve losses from reservoir pressure going below bubble point pressure.

As of 31 December 2022, OKEA's working interest on Nova is 6%. The other licensees are Wintershall Dea Norge AS (operator, 39%), Sval Energi AS (45%), and Pandion Energy AS (10%).

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 licences, as shown in *Table 4*. Apart from Calypso, the contingent resources are verified by a third-party reserves certification performed by AGR Petroleum Services.

Table 4: OKEA Contingent Resources as of 31 December 2022

Discovery - Project	OKEA WI	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
		Low	Base	High	Low	Base	High
Draugen - Infill Drilling	44.56 %	1.44	2.89	4.33	0.64	1.29	1.93
Draugen - Increased water injection	44.56 %	1.64	3.28	4.92	0.73	1.46	2.19
Draugen - Garn West Sør	44.56 %	2.83	5.50	7.48	1.26	2.45	3.33
Draugen	**44.56 %**	**5.91**	**11.67**	**16.73**	**2.63**	**5.20**	**7.46**
Gjøa - Gjøa Nord	12 %	12.16	23.64	34.80	1.46	2.84	4.18
Gjøa - Oil well interventions	12 %	1.21	1.70	2.09	0.15	0.20	0.25
Gjøa - Tail production	12 %	3.58	7.15	14.22	0.43	0.86	1.71
Gjøa	**12 %**	**16.94**	**32.48**	**51.13**	**2.03**	**3.90**	**6.14**
IAA - Infill Drilling IAOP-4D 1	9.239 %	1.57	3.14	4.71	0.14	0.29	0.43
IAA - Infill Drilling IAOP-4D 2	9.239 %	1.19	2.39	3.58	0.11	0.22	0.33
IAA - Infill Drilling IAOP-4D 3	9.239 %	1.23	2.46	3.69	0.11	0.23	0.34
IAA - levetidsforlengelse	9.239 %	3.69	7.37	14.19	0.34	0.68	1.31
IAA - More infill wells	9.239 %	2.25	4.50	8.99	0.21	0.42	0.83
Ivar Aasen	**9.239 %**	**9.93**	**19.86**	**35.17**	**0.92**	**1.83**	**3.25**
Brage - Statfjord Prod & Talisker WI	35.2 %	1.61	2.78	3.97	0.57	0.98	1.40
Brage - IOR infill wells	35.2 %	6.48	6.94	7.24	2.28	2.44	2.55
Brage - Climate Response	35.2 %	2.00	2.85	3.71	0.70	1.00	1.31
Brage - Talisker West	35.2 %	1.54	4.27	7.01	0.54	1.50	2.47
Brage - EOR	35.2 %	6.72	13.45	20.17	2.37	4.73	7.10
Brage - Sognefjord template project	35.2 %	6.87	13.74	20.62	2.42	4.84	7.26
Brage	**35.2 %**	**25.23**	**44.04**	**62.71**	**8.88**	**15.50**	**22.07**
Galtvort	**40 %**	**4.50**	**9.01**	**13.51**	**1.80**	**3.60**	**5.40**
Aurora	**65 %**	**10.41**	**13.34**	**19.84**	**6.76**	**8.67**	**12.90**
Nova - Infill wells	**6 %**	**12.96**	**17.39**	**22.90**	**0.78**	**1.04**	**1.37**
Yme - Infill Drilling	**15 %**	**1.51**	**3.02**	**4.47**	**0.23**	**0.45**	**0.67**
Calypso	**30 %**	**7.0**	**10.0**	**13.0**	**2.10**	**3.00**	**3.90**
Total Contingent Volumes					**26.13**	**43.20**	**63.16**

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. Draugen IOR

The Draugen asset is described in section 3.3.1. The "Draugen IOR Programme" was initiated in 2019 to increase the ultimate recovery from the field. Following screening of several alternative

IOR methods/technologies upgrading the subsea pump was considered as the most promising options and has been further matured.

Garn West South: During 2020 and 2021, the infill well target "Garn West South" close to the existing producer well D-2 H was identified and subsequently matured towards an investment decision in autumn 2021. The target was first planned to be drilled from slot D-2, and later from D-1. Due to operational experiences/limitations, these plans were abandoned, and the associated volumes were downgraded from reserves to contingent resources in 2022.

Instead, the license has decided to appraise both the Garn West South target and the Springmus prospect before making an investment decision. These appraisal wells are likely to be drilled in 2023.

Dependent on results from these wells, the Garn West South target might be drilled from well slot D-1 or a new subsea satellite structure close to the Garn West Manifold, leaving existing well D-2 H to continue in production.

Increased injection: The potential for increased injection by restoring PWRI to the NWIT is currently investigated by injection at a high rate in the NWIT wells B-2 and B-5.

Infill drilling: No specific targets were qualified for further maturation during the "Draugen IOR programme" but efforts linked to mapping and modelling of the field are being pursued.

4.2.2. Brage IOR

The Brage asset is described in section 3.3.2. Main method for increase 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. In 2023 four wells to infill and development well targets are under maturation (A-11 D/E, A-37 C, A-13 D and a Statfjord/Cook producer). Two well projects are planed into reservoirs that has not been produced from earlier and requires PDO except applications and subsequent approvals. Also, a water injection well to support the Talisker producers is being planned for commencement in 2023, in case this will be beneficial. In addition to the infill/development wells described above, the potential in Shetland and the potential in the Kim prospect will be evaluated in 2023.

4.2.3. Gjøa Nord

The Gjøa asset is described in section 3.3.3. The Gjøa Nord development project covers the discoveries Hamlet and Hamlet North, c.f. Figure 7. Hamlet North was proven in 1997 by Norsk Hydro through the well 35/9-3 T2, while Hamlet was proven in spring 2022 by Neptune. Both discoveries are in the licences PL153 (Gjøa) and PL153 C.

Reservoir

The Gjøa Nord reservoir is composed of stacked turbiditic sands from the Agat Fm. Three main sands are identified from seismic and well observations: Sand 2, Sand 3 in Hamlet and Sand 5 in Hamlet North. Sand 2 has a NTG of 73 %, Sand 3 54% and Sand 5 roughly 49%. The sands permeabilities are between 10 and 400 mD. Sand 5 in the North is probably isolated from Hamlet South. Compartmentalization in Hamlet South is under assessment.

Development

The planned drainage strategy is managed pressure depletion with concurrent oil rim production with up to three producer wells. The well flow would be brought back to Gjøa via the G template (P-1 segment). An investment decision regarding a joint development of these two discoveries alone was attempted, but not obtained in 2022. The license is now evaluating alternative options to develop the two discoveries, e.g. together with the nearby Ofelia discovery.

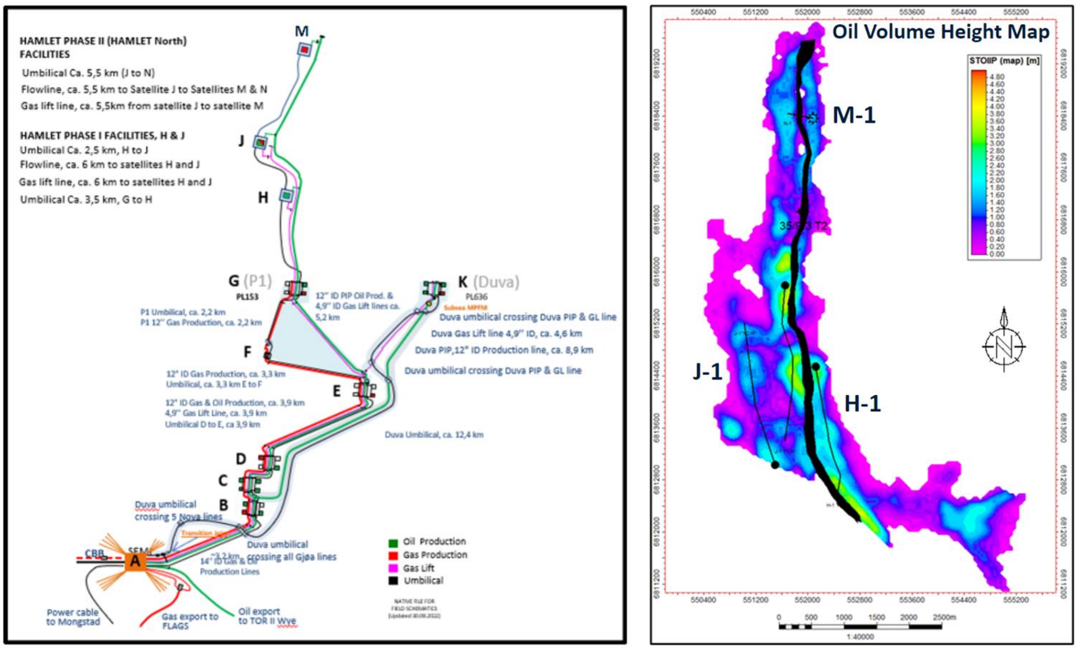

Figure 7: Proposed Gjøa Nord development solution

4.2.4. Gjøa IOR

The operator reports in RNB2023 contingent volumes related to a possible intervention into oil well B-1 and tail production. These volumes are included in the ASR.

4.2.5. 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. Note that OKEA working interest has increased since ASR 2021.

4.2.6. Aurora (PL195)

The Aurora discovery is situated in licences PL195 and PL195 B, approximately 20 km west of Gjøa, c.f. *Figure 4*. OKEA became operator of the two licences 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 Fm. sandstones. No gas/water contact was apparent, indicating gas down to 3 511m TVDSS. The water depth in the area is about 373m.

The discovery was appraised by well 35/8-4, which encountered no hydrocarbons, indicating water up to 3 611m 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 70m with a net pay of

31.9m. Average porosity in the net sand was 15.6% with an estimated average water saturation of 22%. Reservoir temperature is about 90 degrees 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 2023. First gas from Aurora could then be produced in 2027, given a positive outcome of the appraisal well and available capacity at Gjøa.

4.2.7. Galtvort (PL1060)

The Galtvort gas discovery is located in license PL1060, approximately 12 km northwest of the Draugen field, c.f. *Figure 2*. Equinor is the operator with a 31% interest, partners are OKEA (40%), Chrysaor (20%) and Longboat (9%).

Discovery

Galtvort was discovered in 2008 through well 6407/8-4 S, with a sidetrack 8-4 A into the northern segment. The gas bearing reservoir is located in Garn and Tilje formations and with a total column of 65m.

Reservoir

The reservoir quality at Galtvort is good, with permeability ranging from 100-1000 mD and porosity averaging around 30%. The discovery is divided in 2 segments, Galtvort Central and Galtvort South, divided by a local saddle point. The GWC identified in well 8-4S is located at 2 160m, and pressure is hydrostatic.

Development

The discovery is likely to be developed with one horizontal well and depletion as drive mechanism. A low-cost tie-back to Draugen can be achieved by building on the Hasselmus development only 5 km south and midway between Draugen and Galtvort as described above.

Status

A Galtvort development project is not yet formally initiated. The Galtvort discovery may be developed either as tie-back to Draugen via Hasselmus or together with the new discovery. Compared to last year, contingent resources are unchanged.

4.2.8. Calypso (PL938)

The Calypso gas and oil discovery is located in licence 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 mD and porosity averaging aroung 21 %. The OWC is interpreted from pressure points and a total column from the OWC 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 horisontal well with one water injector as drive mechanism. A low-cost tie-back to Draugen may also be achieved with an alternative solution where one horisontal well is drilled, and pressure depletion is the main driving mechanism. The operator will also consider Njord as a potential tie-back solution.

Status

A Calypso development project is not yet formally initiated. The discovery may be developed either as a tie-back to Draugen or Njord. The licence has applied for an extension of the BoK deadline with one year. The new BoK deadline is 2 March 2024.

4.2.9. Nova IOR

The Nova asset is described in section 3.3.6. The operator reports in RNB2023 contingent volumes related to possible infill drilling. 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 68 USD/bbl (real 2022 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).

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