Annual statement of reserves and resources

Annual report 2021

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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 is 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 2021, with cut-off date 31.12.2021.

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.

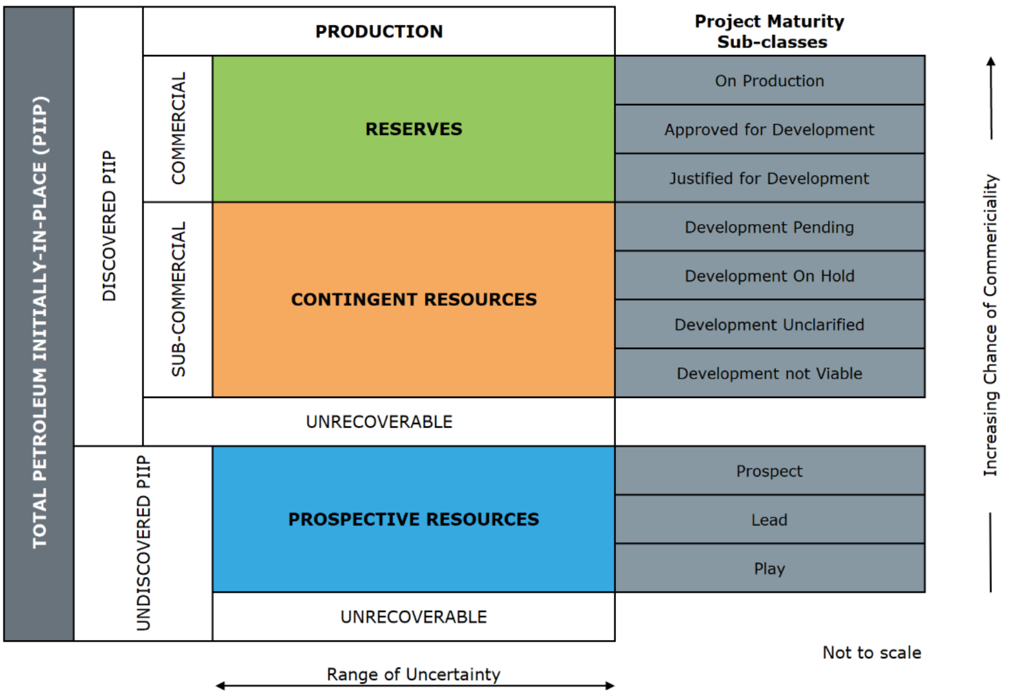

Figure 1: PRMS including sub-classes based on maturity

3 Reserves

OKEA ASA ("OKEA") has reserves distributed across four 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 31.12.2021

Field/Project	OKEA Working Interest	Operator	Project Status Category	Comment
Draugen field	44,560 %	OKEA	On production	Main portion of OKEA reserves.
Hasselmus discovery	44,560 %	OKEA	Approved for Development	Part of Draugen field
Gjøa field	12,0 %	Neptune	On production	Includes P1 development
Ivar Aasen field	0,5540 %	Aker BP	On production	
Yme field	15,0 %	Repsol	On production	First oil October 2021

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 $66/bbl, with a long-term currency rate of NOKUSD 8.0. Gas price and NGL prices are set to 2.00 NOK/Sm^3 and 475 USD/ton, respectively. 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 - 1000 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 31.12.2021 are estimated at 35.8 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 46.6 million barrels of oil equivalents. The reserves figures account for the effects of production in 2021. The split between oil, NGL and gas, and between individual assets is given in *Table 2*. The reserves numbers are verified by a third party reserves certification performed by AGR Petroleum Services AS.

Table 2: OKEA Reserves as of 31.12.2021.

Asset/Project	OKEA WI (%)	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil (mmboe)	Gross NGL (mmboe)	Gross Gas (mmboe)	Gross oe (mmboe)	Net oe (mmboe)	Gross Oil (mmboe)	Gross NGL (mmboe)	Gross Gas (mmboe)	Gross oe (mmboe)	Net oe (mmboe)
Draugen	44,56 %	41,15	2,23	5,99	49,37	22,00	51,94	2,53	8,23	62,71	27,94
Gjøa	12,00 %	3,23	10,71	24,99	38,93	4,67	4,59	17,47	40,75	62,81	7,54
Ivar Aasen	0,554 %	45,11	3,06	9,55	57,72	0,32	58,51	3,89	12,16	74,57	0,41
Yme	15,00 %	58,98	0,00	0,00	58,98	8,85	71,45	0,00	0,00	71,45	10,72
Total Net oe						**35,8**					**46,6**

Please note that totals in tables above are arithmetic and not stochastic summations.

The corresponding 3P/P10 estimate of net OKEA reserves is 56.8 mmboe. For comparison, the corresponding Total Net 1P-, 2P- and 3P-reserves in ASR 2020 (31.12.2020) were 33.6, 41.6 and 50.6 mmboe, respectively, c.f. *Table 3*.

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 2020 (31.12.2020). "Production" is primarily related to the Draugen and Gjøa assets. "Revisions of previous estimates" on Gjøa relate to results from P1 drilling operations, production experience, and model updates, including history match. For some assets, 1P volumes are reduced as result of earlier economic cut-off.

Table 3: OKEA Reserves Development from 31.12.2020 to 31.12.2021

Reserves Development												
Asset	EoY 2020		Production		Revisions of previous estimates		Projects matured		New Developments		EoY 2021	
	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	**19,7**	**22,96**	-2,56	-2,56	0,06	0,51	1,24	2,42	3,57	4,62	**22,00**	**27,94**
Gjøa	**6,41**	**8,59**	-3,16	-3,16	1,41	2,10	0,00	0,00	0,00	0,00	**4,67**	**7,53**
Ivar Aasen	**0,27**	**0,57**	-0,09	-0,09	0,13	-0,08	0,01	0,02	0,00	0,00	**0,32**	**0,42**
Yme	**7,21**	**9,43**	-0,10	-0,10	0,00	0,00	1,74	1,39	0,00	0,00	**8,85**	**10,71**
Total	**33,6**	**41,6**	-5,9	-5,9	1,6	2,5	3,0	3,8	3,6	4,6	**35,8**	**46,6**

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 located in the Norwegian Sea at 250 meters water depth, approximately 140 km Northwest of Kristiansund, 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, and initial testing confirmed an oil rate of more than 8 000 bbl per day.

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 of 77 000 bbl per day.

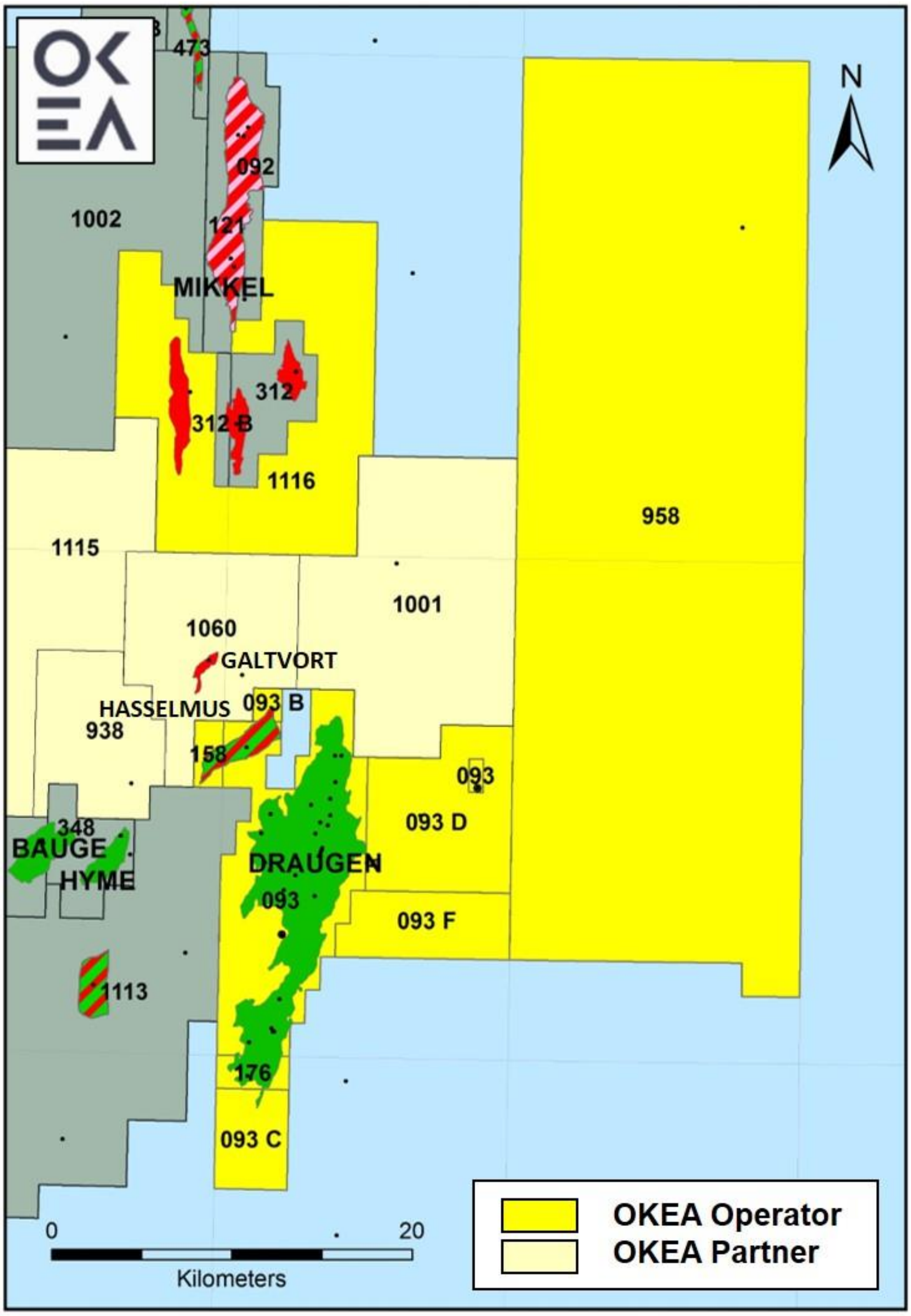

Figure 2: Draugen field location and adjacent area (Norwegian Sea). OKEA operates licences highlighted in yellow and is partner in PL1060, PL1001 and PL938

Development

The field is developed with a concrete gravity-based structure (GBS), with full oil stabilisation and storage capabilities, c.f. Figure *3*. 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 bbls 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, five out of six platform wells and nine out of eleven subsea wells are in operation, in addition to two subsea water injectors. In the subsea production system, D-1 AH is shut-in due to high water cut, G-3 H is injecting condensate that cannot be exported while gas is imported for fuel. Subsea well G-2 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.

Figure 3: Draugen Platform

The reserves estimates are based on the RNB2022 submission by OKEA, assuming production until economic field lifetime at end of 2035. OKEA has the ambition to extend the field lifetime to at least 2040, which would add further reserves and allow tie-in of more resources.

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 Neptune Energy Norge AS[1] (7.56%).

D-1 H sidetrack

During 2020 and 2021, an infill well target close to the existing producer well D-2 H was identified and matured towards an investment decision. Having been shut in due to scale problems, D-2 H was put back in production in May 2021 after a successful Light Well Intervention. A production test has proved a daily rate for D-2 H of 200 Sm3/d in September 2021.

The sidetrack target was initially planned as a fall-back plan if D-2 H was not restored to production but still holds an interesting business case, both because of an acceleration effect and also a significant increase in reserves. A decision to drill a sidetrack from D-2 H was therefore taken in the licence in Autumn 2021. Associated hydrocarbon volumes are consequently reported as reserves. Timing of the sidetrack operations will depend on future production experience with

[1] 12th November 2021 Neptune announced the sale of their working interest in Draugen to M Vest Energy AS

the existing well D-2 H, and the time necessary for refurbishing the X-mas tree. It is now, however, likely that the sidetrack will instead be drilled from an alternative well slot (D-1), leaving D-2 H to continue in production.

Hasselmus

Hasselmus is a gas discovery with a thin oil leg, located 7km northwest of the Draugen field. The structure was discovered by well 6407/9-9 in 1999.

The reservoir is a sand-prone interval of tidally influenced shallow marine deposits, interpreted to be laterally continuous with high Net to Gross, 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. In order to cater for future tie-ins from third party licences, a 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. The drilling operations are planned for summer 2022, and 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, see above, will provide sufficient gas to avoid gas import for Draugen fuel consumption and thereby allows 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.

3.3.2. Gjøa (PL153)

The Gjøa field is located 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.

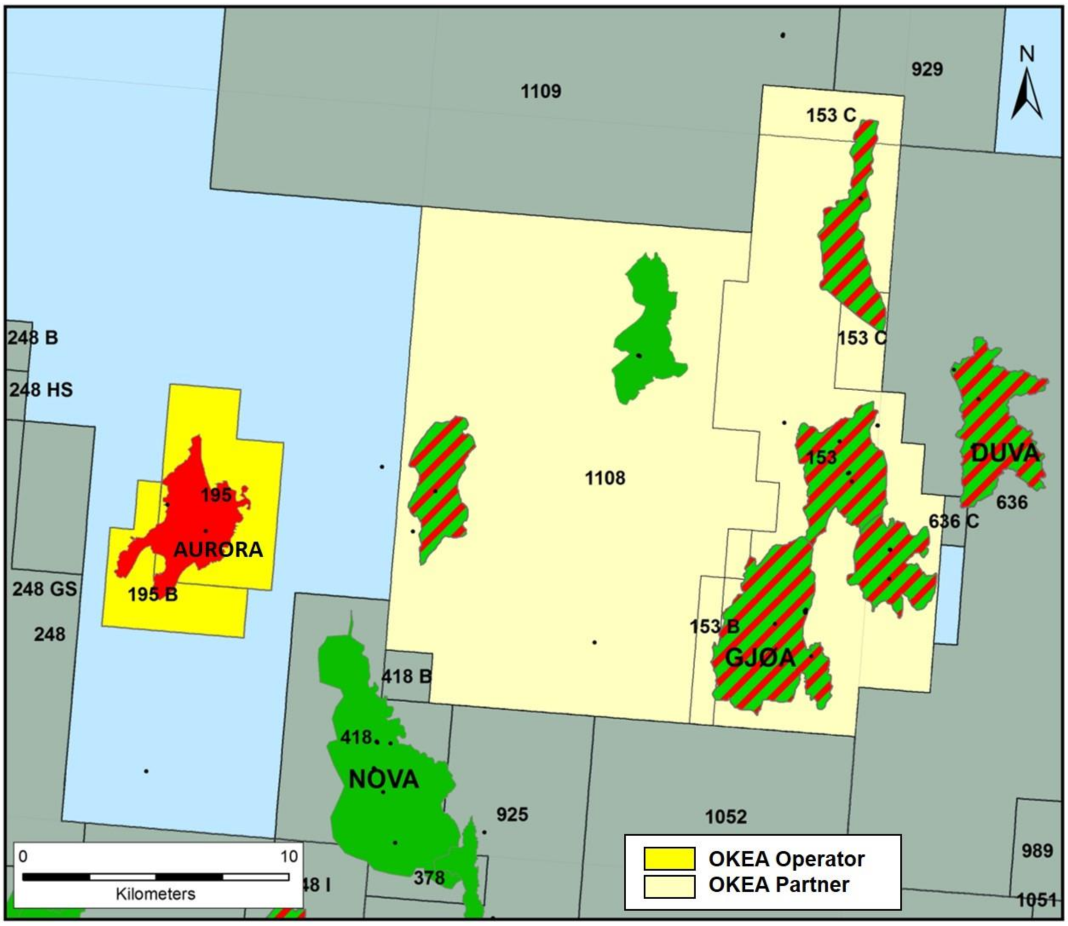

Figure 4: Gjøa field location (North Sea)

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. Testing confirmed an oil rate of 5 680 bbl/d (Dunlin Fm.) and gas rates of 0.6 and 0.9 MSm^3/d (Brent and Viking).

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 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 9000 MSm^3/d and a declining oil rate of approximately 10 000 bbl/d. Despite being expected to die in the spring of 2020, all oil wells were still on stream at the accelerated start-up of Duva mid-August 2021, except for C-2, C-3 and C-4. The production in 2021 has been significantly better than the RNB2021-prognosis, mainly due to longer lifetime of the oil wells, P1 overperforming but also due to less shut down days than prognosed.

Gjøa is already host for the Vega field, became host for Duva in august 2021 and will be host for Nova field 2022.

The reserves estimate for Gjøa is based on the RNB2022 submitted by the operator, Neptune Energy, and includes reserves from the main field and reserves related to the P1 redevelopment project which was sanctioned by the licensees in February 2019. Three pilot wells were drilled in spring 2020 to help optimising the P1 project. Based on the results from the pilots, it was decided to drill only 2 producers: one gas producer G-1 and one oil producer G-4. The reserves associated with the P1 project have consequently been reduced. However, the wells have started producing in February 2021 and are over performing. The reserves for P1 are therefore increased in RNB2022. The main field reserves are also increased due to lower decline than prognosed, especially in the P5 segment.

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

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

3.3.3. 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.

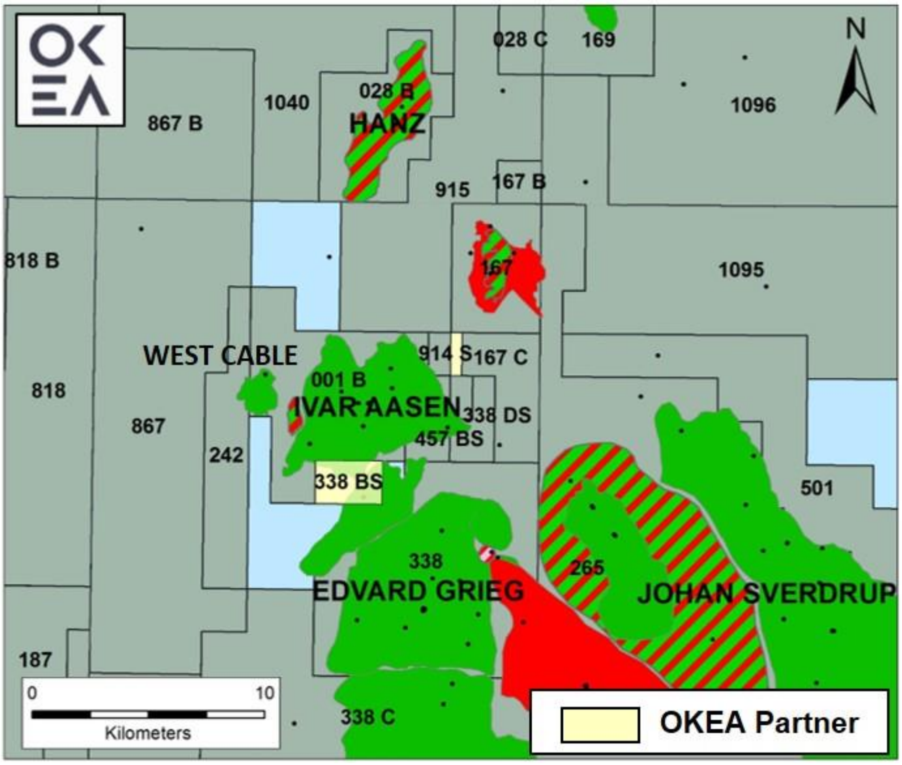

Figure 5: Ivar Aasen and West Cable location map, North Sea

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 will also cover Ivar Aasen power demand until a joint solution for power from shore is established.

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 35 000 bbl/d, together with some associated gas. The oil production from Ivar Aasen during 2021 was slightly below the RNB2021 prognosis. The main causes for the production losses during 2021 relate to operational challenges at Edvard Grieg, drilling operations and disappointing results of the new producer D-13. In addition, production is reduced in order to preserve long term reserves by maintaining reservoir pressure.

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

Drilling of two wells D-13 B and D-4 A was completed during 2021. D-13 B that was planned for production found the encountered reservoir rock tight and was plugged back for a new side-track in 2022. D-4 A will start water injection early 2022.

Three new wells, one injector (D-8 A) and two producers (D-9 C and D-13 B), are planned drilled during 2022.

The reserves estimate for Ivar Aasen is based on the RNB2022 submitted by the operator, Aker BP. OKEA holds a 0.554% working interest in the unit. The other licensees are Aker BP (Operator, 34.7862%), Equinor Energy AS (41.4730%), Spirit Energy Norway AS (12.3173%), Wintershall Norge AS (6.4615%), Neptune Energy Norge AS (3.0230%) and Lundin Norway AS (1.3850%).

3.3.4. 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. 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.

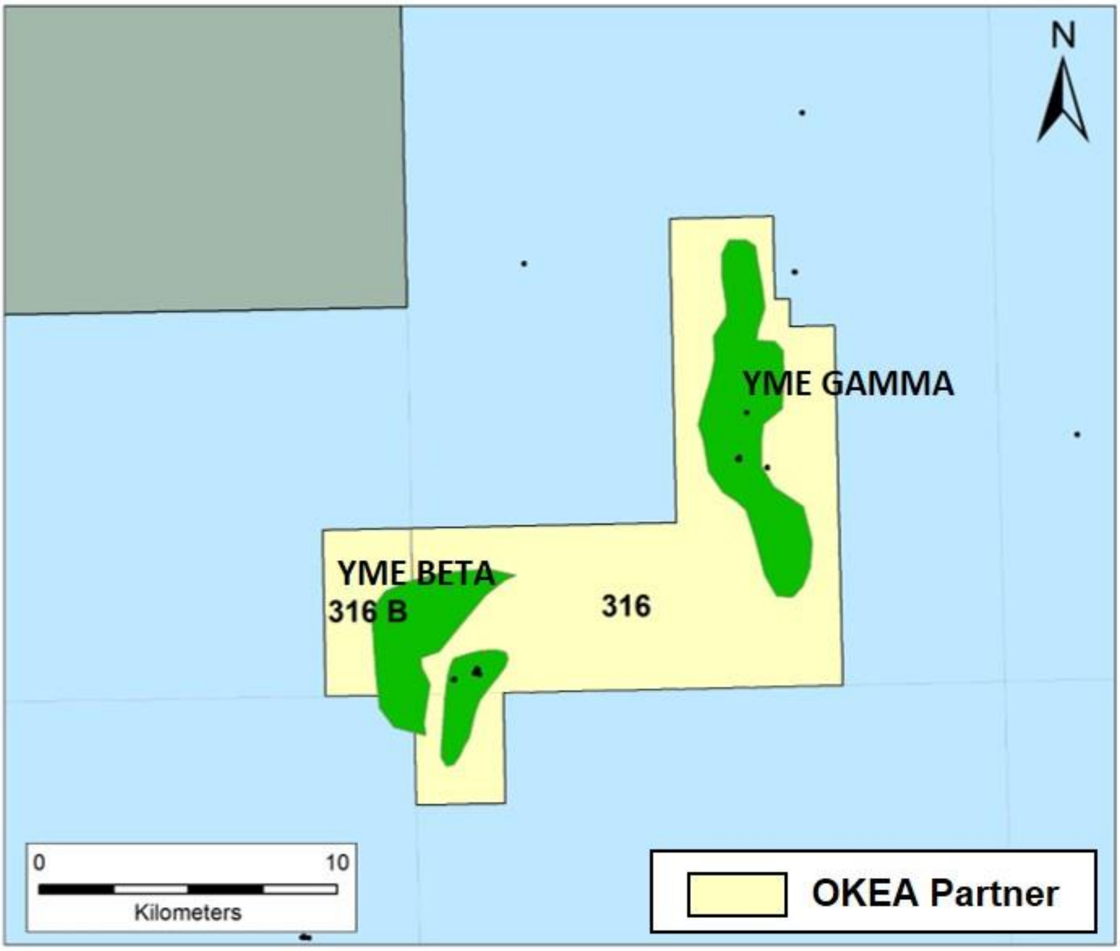

Figure 6: Yme Gamma and Beta location map, North Sea

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/d 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. However, 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 will be exported by tanker.

The field will produce from 12 horisontal 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.

Status

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

In 2019, the caisson permanent support (CPS) and the well-head module were both installed.

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.

Drilling of new Gamma wells and new Beta wells is scheduled to start in 2022.

The reserves on Yme are based on RNB2021 as submitted by the operator but adjusted with respect to OKEA's expectations regarding production in 2021. In RNB2022, the operator has presented updated production profiles according to results from a new full-field model, leading to slight reduction in reserves. Since no new information from the reservoir has been included in this model, OKEA chooses to disregard this update.

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 KUFPEC Norway AS (10%).

Yme lifetime extension

In both RNB2021 and RNB2022, the operator reports contingent resources related to a "Yme lifetime extension" project, associated to a possible extension of the 10-year contract with Mærsk regarding the Inspirer rig. During 2021, however, the rig was sold to Havila and a lease-contract with the Yme license was established. The terms of this contract essentially remove the need for a new investment decision in 2030. OKEA therefore chooses to report economic volumes in this profile from RNB2021 as reserves.

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).

OKEA holds contingent resources in several licences, as shown in *Table 4*. The contingent resources are verified by a third-party reserves certification performed by AGR Petroleum Services. The following chapter gives a brief description of these contingent resources.

Table 4: OKEA Contingent Resources as of 31.12.2021

PL	Discovery/Project	OKEA Interest	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
			Low	Base	High	Low	Base	High
093	Draugen - Infill Drilling	44,560 %	1,42	2,82	4,24	0,63	1,26	1,89
	Draugen - Increased water injection	44,560 %	1,63	3,28	4,90	0,73	1,46	2,18
	Draugen - Power from Shore	44,560 %	4,14	5,16	6,19	1,84	2,30	2,76
	Draugen - Subsea Pump Upgrade	44,560 %	1,65	3,30	4,96	0,74	1,47	2,21
	Draugen - Production past cut off	44,560 %	6,25	8,46	10,42	2,79	3,77	4,64
	Draugen total		**15,09**	**23,03**	**30,71**	**6,72**	**10,26**	**13,68**
153	Gjøa - Oil well interventions	12,0 %	1,21	1,70	2,09	0,15	0,20	0,25
	Gjøa - Tail production	12,0 %	3,58	7,15	14,22	0,43	0,86	1,71
	Gjøa total		**4,79**	**8,86**	**16,31**	**0,57**	**1,06**	**1,96**
Ivar Aasen Unit	IAA - Infill Drilling IAOP-W-SK2	0,5540 %	2,09	4,18	6,28	0,01	0,02	0,03
	IAA - Infill Drilling IAWI D-8 A	0,5540 %	1,59	3,17	4,76	0,01	0,02	0,03
	IAA - Infill Drilling IAOP-E-V	0,5540 %	1,44	2,90	4,34	0,01	0,02	0,02
	IAA - More infill wells	0,5540 %	2,89	5,79	8,68	0,02	0,03	0,05
	Ivar Aasen total		**8,02**	**16,04**	**24,06**	**0,04**	**0,09**	**0,13**
195	Aurora (35/8-3)	65,0 %	10,30	14,17	23,70	6,70	9,21	15,41
1060	Galtvort (6407/8-4 S)	40,0 %	4,50	9,01	13,51	1,80	3,60	5,40
Total Contingent Volumes						**15,8**	**24,2**	**36,6**

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.

4.1. Draugen - Increased Oil Recovery

In late 2019 a "Draugen IOR Programme" was initiated to increase the ultimate recovery from the field. Following screening of several alternative IOR methods/technologies, infill drilling and upgrading the subseas pump are considered as the most promising options and will be further matured. A feasibility milestone is planned for early in 2022 and may result in a decision to drill appraisal well(s) to de-risk specific infill targets.

4.2. Gjøa – B-1 well and tail production

The operator reports in RNB2022 contingent volumes related to a possible B-1 intervention and tail production, and these are included in the ASR.

4.3. Ivar Aasen - Infill Drilling

Several infill drilling opportunities have been identified on Ivar Aasen and are currently in various stages of maturation.

4.4. Aurora

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 3511 m TVDSS. The water depth in the area is about 373 m.

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 31.9m. 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, but available data suggests that the gas has similar quality as Vega North.

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 utilising existing infrastructure in the area, related to the Vega, Nova and/or Gjøa developments.

Status

The development project was initiated in September 2020, working towards a decision to drill an appraisal well in 2022. First gas from Aurora could be produced already in 2025, given a positive outcome of the appraisal well, and available capacity at Gjøa.

4.5. Galtvort

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 8-4S is located at 2160m, and pressure is hydrostatic.

Development

The discovery is likely to be developed with one horisontal 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. Instead, exploration drilling of the Ginny prospect in PL1060 is prioritised. Dependent on the results of the Ginny well (likely available early in 2022), 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 reduced as result of a review of the simulation models.

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 percent, a long-term exchange rate of USDNOK 8.0, and a long-term oil price of 66 USD/bbl (real 2021 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 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 disipline.

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