2019

Annual Statement
of Reserves and
Resources

TABLE OF CONTENTS

1 INTRODUCTION 3
2 CLASSIFICATION OF RESERVES AND CONTINGENT RESOURCES 3
3 RESERVES 4
3.1. TOTAL RESERVES ESTIMATES 4
3.2. DEVELOPMENT OF RESERVES 5
3.3. DESCRIPTION OF RESERVES 5
3.3.1. Draugen (PL093) 5
3.3.2. Gjøa (PL153) 8
3.3.3. Ivar Aasen Unit (PL338BS) 9
3.3.4. Yme (PL316) 11
4 CONTINGENT RESOURCES 13
4.1. GREVLING (PL038D) AND STORSKRYMTEN (PL974) 13
4.2. DRAUGEN INFILL DRILLING 15
4.3. HASSELMUS 16
4.4. GJØA - B1 WELL AND TAIL PRODUCTION 16
4.5. YME LIFETIME EXTENSION 16
5 PROSPECTIVE RESOURCES 17
5.1. PL093 – SPRINGMUS, EAST FLANK 17
5.2. PL1001 – DRAUGEN NE 17
5.3. PL958 - RIALTO 17
5.4. PL1003 - MISTRAL 17
5.5. PL910 18
5.6. PL153 - HAMLET 18
5.7. PL973 – JERV, ILDER, MÅR 18
6 MANAGEMENT DISCUSSION AND ANALYSIS 19

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 the Oslo Stock Exchange.

The overview in this document is the final version of the ASR 2019, with cut-off date 31.12.2019. A preliminary version of this document (with cut off data 31.03.2019) was issued in conjunction with the IPO process. Formally, this document represents therefore an update to the ASR 2018 (with cut-off date 31.12.2018), and changes to the resource base, including effects of production in 2019, are reported with respect to the ASR 2018.

2 Classification of Reserves and Contingent Resources

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

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

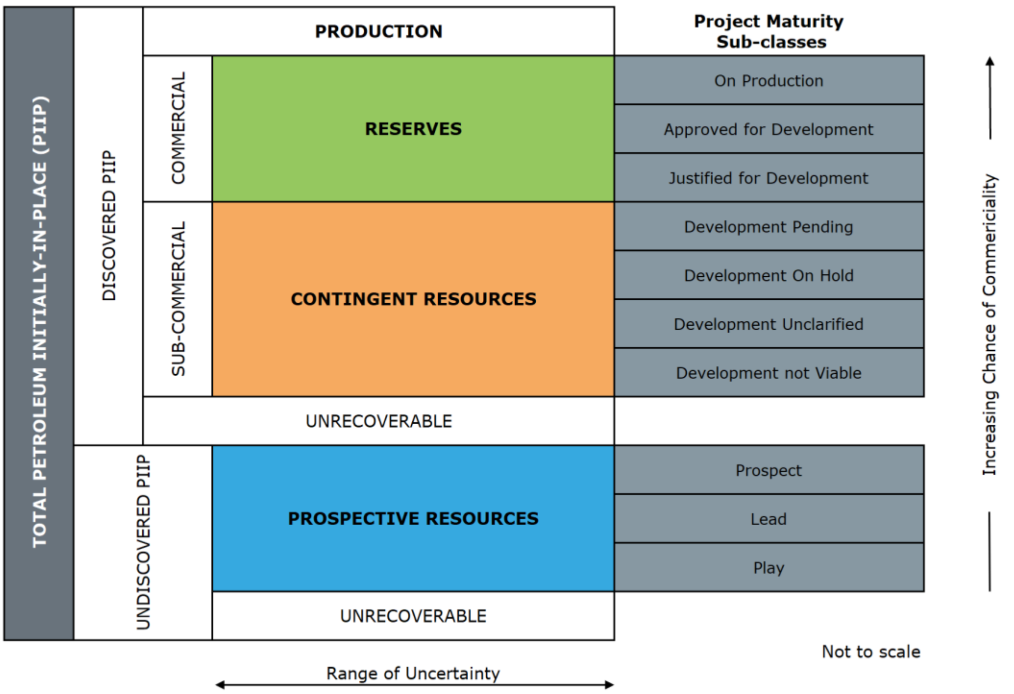

Figure 1: PRMS including sub-classes based on maturity as of June 2018

3 Reserves

OKEA ASA has reserves distributed in 4 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 categorized 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.

Table 1: OKEA asset portfolio with reserves

Field/Project	OKEA Working Interest (%)	Operator	Project Status Category	Comment
Draugen field	44.56 %	OKEA	On production	Main portion of OKEA reserves
Gjøa field	12.00 %	Neptune	On production	
Ivar Aasen field	0.554 %	Aker BP	On production	
Yme field	15.00 %	Repsol	Approved for development	First oil Q2 2020

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 $65/bbl, with a long-term currency rate of USDNOK 8.0. Gas price and NGL prices are set to 60% and 80% of oil price on oil equivalent basis, 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 = 35.3 Scf

NGL - 1 tonne NGL = 1.9 Sm^3 oe

3.1. TOTAL RESERVES ESTIMATES

OKEA's net proven reserves (1P/P90) as of 31.12.2019 are estimated at 40.6 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 49.5 million barrels of oil equivalents. The reserves figures account for the effects of production in 2019. The split between liquid and gas, between assets and between the different subcategories is given in Table 2. The reserves numbers are verified by a third party reserves certification performed by AGR Petroleum Services.

Table 2: OKEA Reserves as of 31.12.2019

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)
Reserves – On Production											
Draugen	44.56 %	52.2	0.2	0	52.5	23.4	59.2	0.2	0	59.4	26.5
Gjøa	12.00 %	3.7	14.5	33.8	52.0	6.2	6.0	20.2	47.2	73.4	8.8
Ivar Aasen	0.554 %	57.5	3.3	9.9	70.7	0.4	97.2	4.8	15.0	116.9	0.6
Total Net oe						**30.0**					**35.9**
Reserves – Approved for Development											
Yme	15.00 %	47.1	0	0	47.1	7.1	63.5	0	0	63.5	9.5
Gjøa - P1	12.00 %	8.2	6.3	14.6	29.1	3.5	10.4	6.9	16.1	33.4	4.0
Total Net oe						**10.6**					**13.5**
Reserves – Justified for Development											
Total Net oe						**0**					**0**
Reserves –Total											
Total Net oe						**40.6**					**49.5**

The corresponding 3P/P10 estimate of net OKEA reserves is 57.3 mmboe. For comparison, the corresponding Total Net 1P-, 2P- and 3P-reserves in ASR 2018 (31.12.2018) were 43.5, 52.4 and 63.2 mmboe, respectively, c.f. *Table 3*.

3.2. DEVELOPMENT OF RESERVES

OKEA's reserves and resources are continually matured through field development work, improvement of technical subsurface models, acquisitions and production. Table 3 shows how the volumes have changed since ASR 2018 (31.12.2018). "Production" stems from primarily from the Gjøa and Draugen assets. Changes under "New Developments" are related to the FID regarding the Gjøa P1-redevelopment project. "Revisions of previous estimates" are primarily related to updates regarding the P90-scenarios for the Gjøa and Yme fields.

Table 3: OKEA Reserves Development from 31.12.2018 to 31.12.2019

Reserves Development								
Net attribute mmboe	On Production		Approved for Development		Justified for Development		Total	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance EOY 2018	**35.7**	**42.8**	**7.8**	**9.6**	**0**	**0**	**43.5**	**52.4**
Production	**-6.9**	**-6.9**					**-6.9**	**-6.9**
New Developments			**3.5**	**4.0**			**3.5**	**4.0**
Revisions of previous estimates	**1.2**	**0.0**	**-0.7**	**-0.1**			**0.4**	**-0.1**
Projects matured								
Acquisition / Disposals								
Extensions and Discoveries								
Balance EOY 2019	**30**	**35.9**	**10.6**	**13.5**	**0**	**0**	**40.6**	**49.5**

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.

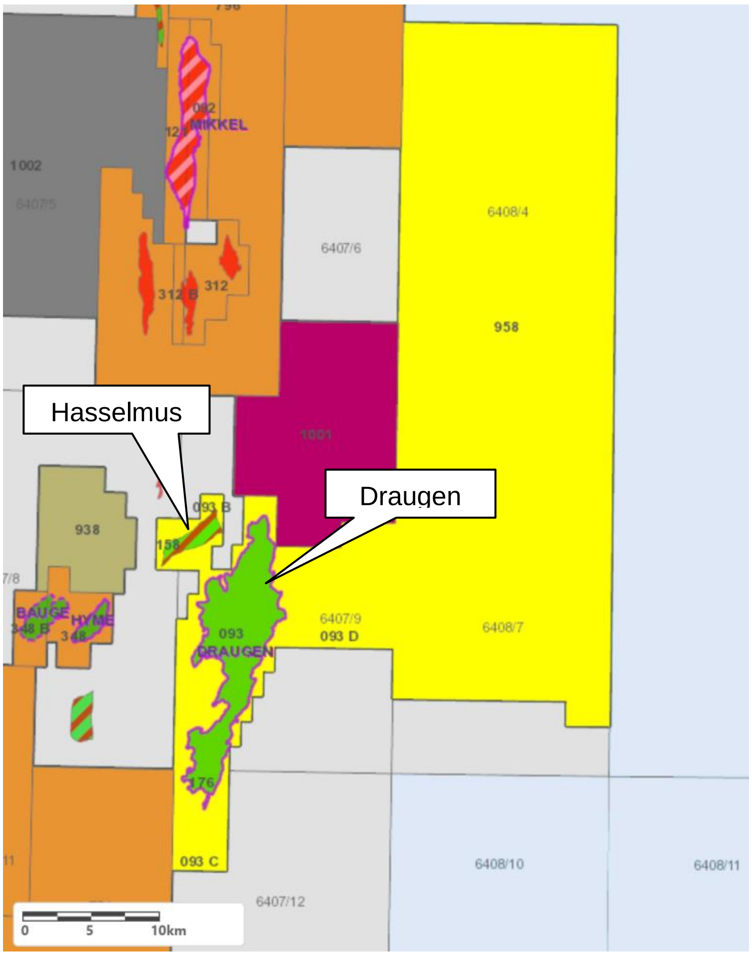

Figure 2: Draugen field location and adjacent area (Norwegian Sea). OKEA operates licences highlighted in yellow and is partner in PL1001

Discovery

The field was discovered with discovery 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/d.

Reservoir

The oil is located in the Garn and Rogn formations, of which the latter holds approximately 90% of the reserves. The reservoir quality is extremely good, 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/d.

Development

The field is developed with a concrete gravity-based structure (GBS), with full oil stabilization and storage capabilities, c.f. *Figure 3*. Oil is exported by shuttle tankers, and gas is exported through an export pipeline connected to the Åsgard Transport System (ÅTS).

The drainage strategy is based on centrally located production wells, supported by downflank water injectors. The field was initially developed with 6 platform wells and 1 subsea well and was later supplemented by a number of subsea wells. Currently 5 platform and 11 subsea wells are in operation, in addition to 2 subsea water injectors. 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 20 000 bbls of oil and 220 000 bbls of water per day. 110 000 bbls of water are reinjected to the reservoir, while the rest is discharged to sea.

All platform wells are producing, except A-5, which is shut in due to high water cut. All subsea wells are also producing, except D-1 which is shut-in due to high water cut. Some subsea wells are produced on cyclic schedule. Production is continuously analysed and optimized by a production management team.

The reserves estimates are based on the RNB2020 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.

In Q4 2019 two appraisal wells were drilled to delineate the targets "Infill Ø" (6407/9-11) and "Skumnisse" (6407/9-12), respectively. Results from the well 6407/9-11 proved that the target area is drained efficiently by existing wells, such that an additional infill well is considered non-economic. The 6407/9-12 showed no reservoir nor traces of hydrocarbons. Further interpretation and studies to calibrate geological understanding of the areas east of Draugen will continue through 2020.

Contingent resources and prospective resources related to the Draugen field are described in Section 4 and 5, respectively.

The OKEA working interest on Draugen is 44.56%. The other licencees are Petoro AS (47.88%) and Neptune Energy Norge AS (7.56%).

Figure 3: Draugen Platform

3.3.2. 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*. The water depth in the area is 360 meters.

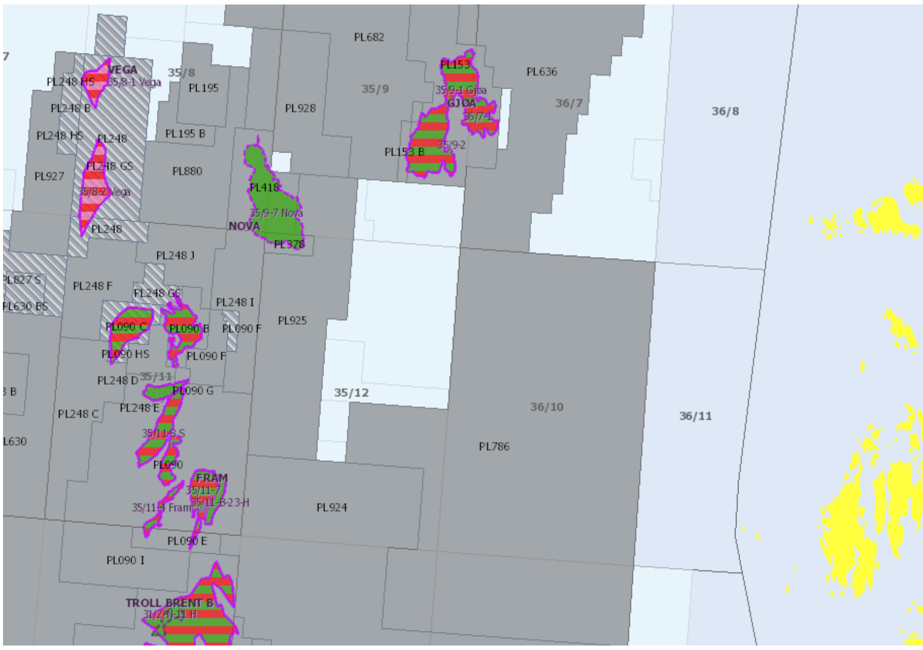

Figure 4: Gjøa field location (North Sea)

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 21.1 and 32.2 MScf/d (Brent and Viking).

Reservoir

The Gjøa reservoir is comprised of 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 7 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 mD to multi-Darcy.

Development

The drainage strategy is managed pressure depletion with concurrent oil rim production. The field is developed with 11 subsea wells, connected to 5 templates and directed back to a semi-submersible unit with full oil stabilization capacities. Advanced well technology with branches and zonal control is implemented, and all wells have multiphase meters and permanent downhole gauges. The oil is exported through a pipeline to the Mongstad terminal, and the 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 field is also the first floating platform with power from shore, reducing the CO_2 emissions by 200 000 tons per year.

Status

The current production has a relatively stable gas rate of more than 9800 Msm3/d and a declining oil rate, currently at 1600 sm3/d. All wells are on stream except the C-2 oil well, which has lift problems. The production in 2019 was marked by a reduction of production in February due to repair on the NGL plant, the Nova shut down of 12 days in August and the unplanned shut down in November due to gas power turbine failure. The 2019 regularity to date, including shutdown, is 89.5%.

Gjøa is already host for the Vega field, and will be host for the Nova and Duva fields within 2021.

The reserves estimate for Gjøa is based on the RNB 2020 submitted by the operator, Neptune Energy, and includes reserves related to the P1 redevelopment project which was sanctioned by the licensees in February 2019. The P1 redevelopment project consists of 3 producers in the P1 segment. Two pilot wells will be drilled in the first half of 2020 and the 3 producers will be drilled from June 2020. Production start is expected for 2020. The net OKEA 2P/P50 reserves from this project are 4 mmboe, in accordance with the operators RNB2020. This implies an increase in reserves with respect to the preliminary ASR 2019 from March 2019, which was based on an early version of the FID-documentation.

Contingent resources related to the Gjøa field are discussed in Section 4. Prospective volumes are addressed in Section 5.

The OKEA 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 (PL338BS)

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 (Figure 5), at a 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 unitized into the Ivar Aasen Unit.

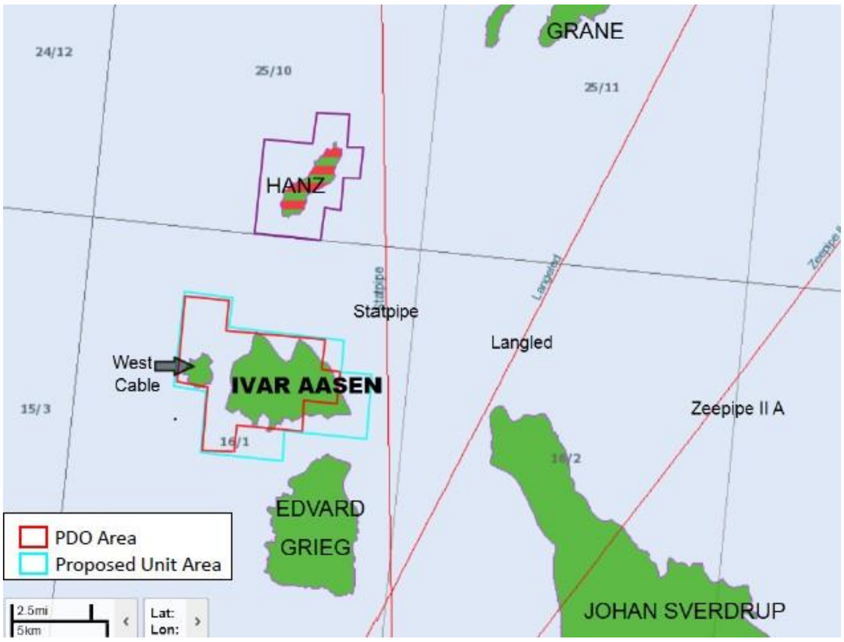

Figure 5: Ivar Aasen and West Cable location map, North Sea

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 2400 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 2950 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 separate 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 stabilization and export. Edward 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

Production from Ivar Aasen started in December 2016, and the current production is at oil plateau at approximately 55 000 bbl/d, together with some associated gas. 2019 oil production from Ivar Aasen are above plan, while gas export is behind as GOR development have not been as expected. Overall HC export volume is prognosed to be very close to expected. Main production losses during 2019 is associated to Edvard Grieg operational challenges and drilling of two IOR wells. During 2019 the voidage replacement rate have been improved also considering the East and West sections balance. However drainage of the eastern section and in particular the Skagerrak formation is still the main uncertainty. Oil producers D-15 and D-18A was drilled and came onstream during 2019. D-15 is a 2-branch multilateral completed in the Skagerrak 2 formation on the east sector at Ivar Aasen. D-18A is a horizontal well completed in the Alluvial fan formation in the west section. Both wells initial production is within expectations, however pressure depletion is observed and addressed in the ongoing evaluation. At current stage it is too early to conclude the impact (if any) on expected volumes.

The reserves estimate for Ivar Aasen are based on RNB2020. OKEA AS holds a 0.554% working interest in the licence. The other licensees are Aker BP (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 was put in production in 1996. The field is located 160 km northeast of the Ekofisk field, c.f. Figure 6, in water depth of 93 meters. Yme ceased production in 2001 after having produced 51 mmboe, as operation was no longer profitable. 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 drilling 9 new development wells and 2 appraisal 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, and in 2018 a revised PDO was approved by the authorities.

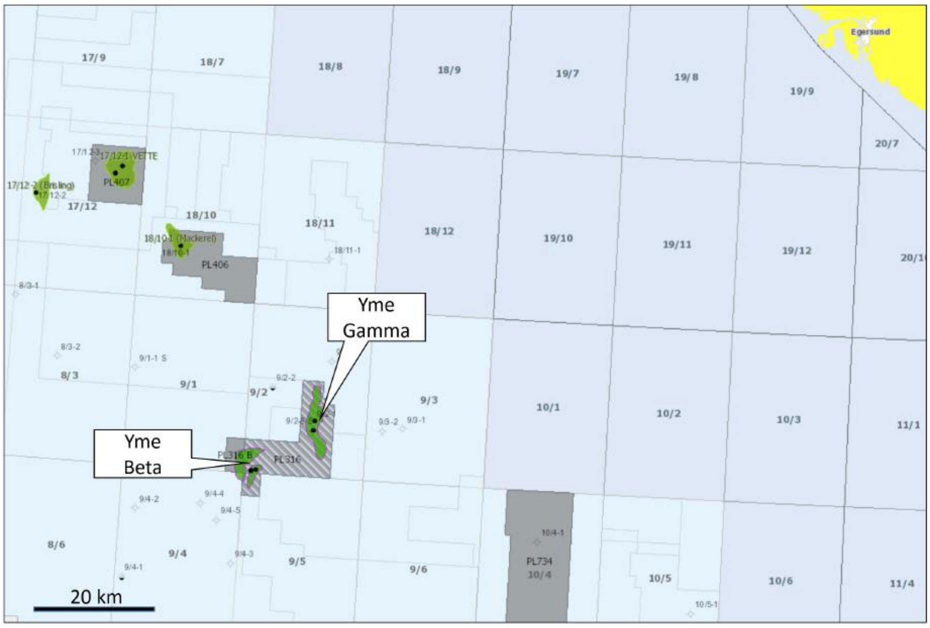

Figure 6: Yme Gamma and Beta location map, North Sea

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 and gas rate of 0.65 MScf/d. 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 3200 meters. Vertically, the reservoir is heterogeneous, and the permeability varies from <1 mD to 2D. The sands are however 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 will be developed with a jack-up MOPU equipped with processing facilities. This will be connected to the existing MOPUSTOR tank, and oil will be exported by tanker.

The field will produce from 12 horizontal production wells, supported by 2 WAG (Water Alternating Gas) injectors and 3 water injectors. Produced water reinjection, in combination with a regional aquifer, will maintain the reservoir pressure, and provide significant sweep towards the producers. Production wells will be artificially lifted by ESPs and gas lift.

Status

The revised PDO was delivered in December 2017 and approved by the authorities in March 2018. First oil is expected in Q2 2020, and the maximum plateau oil production rate is estimated to approximately 53,000 bbl/d.

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

Upgrade of the production unit Maersk Inspirer requires somewhat more time than initially planned for, such that the hook update has been postponed from Q4 2019 to Q2 2020.

The subsurface and well engineering teams are performing final modelling and detailed well planning of the new wells on both Gamma and Beta structures. Drilling of new Gamma wells is scheduled to start in 2020, while new Beta wells are planned to be drilled in 2021-22.

The reserves on Yme are based on RNB2020, which in turn are based on the DG3/FID profiles for the field, apart from an adjustment related to postponed start-up date. OKEA AS holds 15 percent in Yme. The remaining interests are held by Repsol (55%), Lotos (20%) and KUFPEC (10%).

Contingent resources on Yme are related to a lifetime extension, see Section 4.

4 Contingent Resources

Contingent resources are by definition potentially recoverable volumes from proven accumulations, but 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 following chapter gives a brief description of these contingent resources.

Table 4: OKEA Contingent Resources as of 31.12.2019

As of 31.12.2019	Interest	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
		Low	Base	High	Low	Base	High
Hasselmus	44.56 %	5.1	10.3	14.1	2.29	4.57	6.22
Draugen - Infill Æ	44.56 %	2.2	5.7	8.3	0.98	2.52	3.70
Draugen - 100% PWRI	44.56 %	0.0	1.3	1.9	0.00	0.56	0.84
Draugen - Restart of Gas Export	44.56 %	4.4	5.0	5.6	1.98	2.25	2.48
Draugen - Production past 2035	44.56 %	6.4	7.2	8.0	2.83	3.22	3.55
Gjøa - Oil well interventions	12.00 %	1.1	1.7	2.2	0.14	0.20	0.27
Gjøa - Tail production	12.00 %	0.0	7.2	14.2	0.60	0.86	1.44
Grevling	35.00 %	21.4	32.6	47.5	7.51	11.40	16.62
Storskrymten	60.00 %	2.5	9.4	16.3	1.51	5.62	9.77
IAA - Infill Drilling IAOP-W	0.554 %	1.5	3.1	4.6	0.01	0.02	0.03
IAA - Infill Drilling IAOP-E-SK2	0.554 %	1.4	2.9	4.3	0.01	0.02	0.02
IAA - Infill Drilling IAOP-E-V	0.554 %	1.4	2.9	4.3	0.01	0.02	0.02
IAA - More infill wells	0.554 %	3.8	7.5	11.3	0.02	0.04	0.06
IAA - Braid Plain Horst Block	0.554 %	1.4	2.9	4.3	0.01	0.02	0.02
Yme - life extension	15.00 %	7.1	8.8	11.1	1.07	1.32	1.66
Total Contingent Volumes					**19.0**	**32.6**	**46.7**

4.1. GREVLING (PL038D) AND STORSKRYMTEN (PL974)

The Grevling field was discovered by Talisman in 2009. The licence then was transferred to Repsol when they acquired the company. In 2017, operator Repsol relinquished their ownership in the licence and supported the transfer of operatorship to OKEA AS. The field is located approximately 20 km south of the Sleipner field (Figure 7), at water depth of 86 meters. The Grevling discovery has now been matured towards selection of a single development concept and a BoV (decision to continue) is expected in Q2 2020, based on a standalone development concept. The neighbouring Storskrymten discovery, which was licensed to OKEA as operator in the APA 2018 round, is planned to be developed as part of the Grevling project.

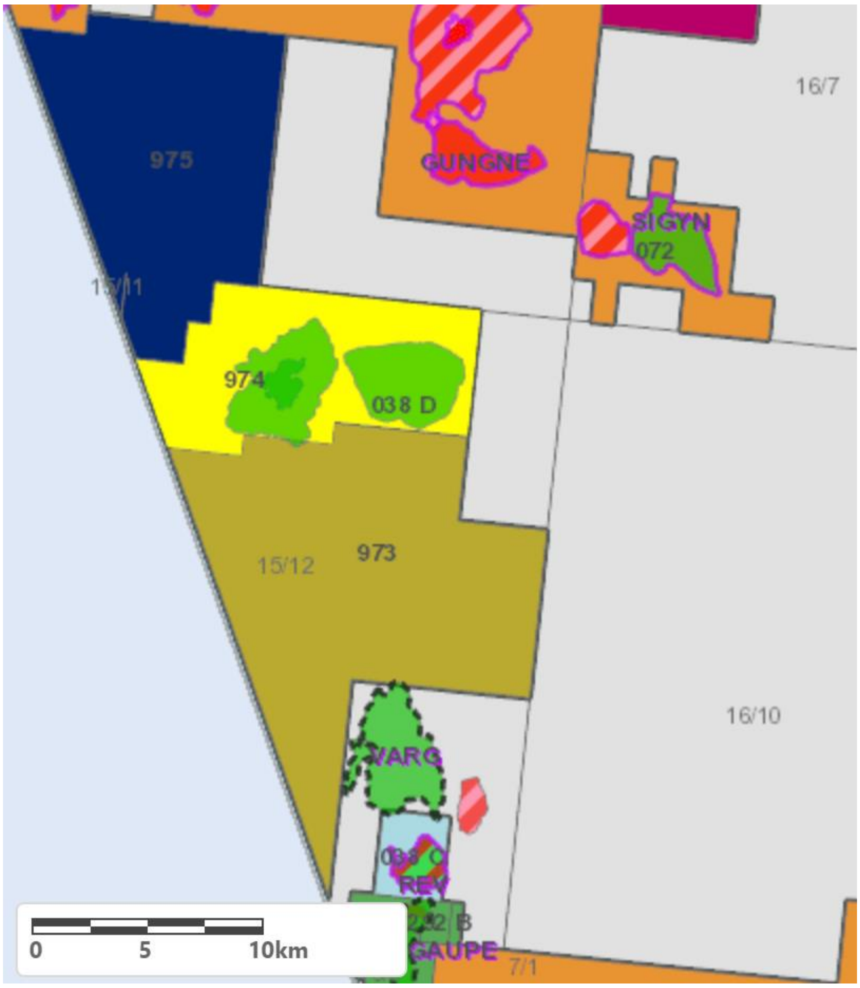

Figure 7: Grevling and Storskrymten location map, North Sea

Discovery

The Grevling field was discovered in 2009 by the 15/12-21 well. The total oil column was 67 meters, and the well tested at rates of up to 780 bbl/d. The discovery was later appraised by a side-track in 15/12-21 A, a new well 15/12-23 and a side-track 15/12-23 A. Storskrymten was discovered in 2007 by the 15/12-18 S well, with a 16m oil column.

Reservoir

The reservoir in Grevling is the Middle Jurassic Hugin and Sleipner fms, and the Triassic Skagerrak Fm. The Sleipner coal Fm separates the Hugin from the Bryne/Skagerrak fms and the accumulation is further subdivided in an eastern and a western segment by a large north-south trending fault. Storskrymten has reservoir in the Paleocene Ty and Heimdal Formations.

Development

The licensees have decided that a standalone development with a mobile production unit (MOPU), as illustrated in Figure 8, is the preferred concept.

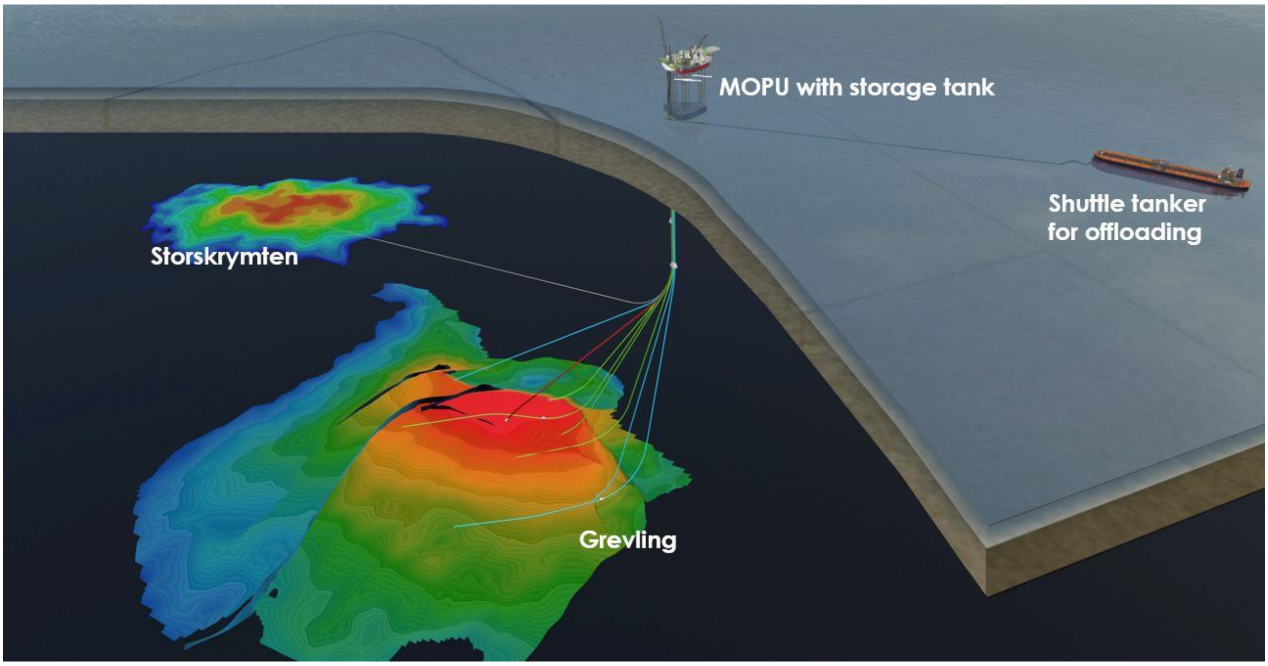

Figure 8: Sketch of MOPU concept

Status

The Grevling project is moving towards a BoV (decision to continue) in Q2 2020, with planned production start-up early 2024. Storskrymten will be included in a joint development project. The contingent resource volumes for Grevling are based on preliminary BoV documentation. Storskrymten resources are based on work regarding the APA2018, but risked down as result of a recent seismic inversion study. A thorough subsurface assessment of the Storskrymten discovery is part of the scope of work for the project. The exploration licence PL973, directly to the south of Grevling and Storskrymten, is operated by Chrysaor. It holds prospective resources that might eventually be included into the Grevling development, see Chapter 5.

OKEA is the operator of PL 038D and holds now a 35% working interest in the license, after Chrysaor has exercised their right to increase their working interest in the license in November 2019. Other partners are Petoro (30%) and Chrysaor Norge (35%). OKEA also operates PL 974 with a 60% working interest, together with Chrysaor Norge (40%) as partner. Also here Chrysaor have increased their working interest in November 2019.

4.2. DRAUGEN INFILL DRILLING

Infill drilling locations are being evaluated to increase recovery from the main Draugen field. A potential infill target "Infill Ø" was appraised in September 2019 by means of well 6407/9-11. Results from this pilot well showed that the target area is drained efficiently with existing wells, such that an additional oil producer is not necessary. However, due to the past success with infill drilling, further infill drilling is likely. One specific infill target ("Infill Æ") is included as contingent resource.

4.3. HASSELMUS

The main contingent resources on Draugen are related to a development of the Hasselmus discovery, c.f. *Figure 2*. The Hasselmus discovery holds both gas and oil, but only the gas is being evaluated for development as tie-in to Draugen. The gas will partly used for fuel at Draugen, and partly for export through the Åsgard Transport pipeline. After a successful BoK (DG1) in autumn 2019, a BoV (DG2) is expected in Q1 2020, aiming for first gas in mid 2022.

4.4. GJØA - B1 WELL AND TAIL PRODUCTION

A change-out of the gas lift valve for the B-1 well by LWI is planned in 2020. If successful, the measure is expected to increase the net OKEA 2C-volumes by 0.2 mmboe.

The operator also reports in RNB2020 contingent volumes related to a possible tail production, and these are included in the ASR with a net 2C-volume of 0.86 mmboe.

4.5. YME LIFETIME EXTENSION

Yme lifetime extension is associated with extending the lifetime of the Maersk Inspirer rig. Current classing approval period extends for 10 years, and contingent volumes are associated with a 5-year extension.

5 Prospective resources

Prospective resources are defined as potential, recoverable volumes from undiscovered accumulations. Table 5 shows the total overview of these resources. Operatorship of the PL958 licence was transferred from A/S Norske Shell to OKEA ASA on 31 January 2019. In addition, OKEA holds interests in four licences that were awarded in March 2019, as result of the APA 2018 round. Two exploration targets were tested in 2019, the Skumnisse and the Kathryn prospects, both dry. There has therefore been an increase from 174 to 269 mmboe unrisked prospective resources since ASR 2018.

Table 5: OKEA Prospective Resources as of *31.12.2019*

PL	Prospect	Interest (%)	Prob. of Discovery	Net unrisked resources (mmboe)			Net Base risked resources (mmboe)	Possible first well	Main HC phase
				Low	Base	High			
PL093	Springmus E	44.56 %	37 %	0.2	2.8	7.9	1.0	2021	Oil
	Springmus W	44.56 %	33 %	0.1	1.2	3.5	0.4	2021	Oil
	East Flank	44.56 %	35 %	0.0	1.1	3.0	0.4	2021	Oil
PL1001	Draugen NE	20.00 %	22 %	4.5	23.5	65.5	5.2	2021	Oil
PL958	Rialto	50.00 %	12 %	46.8	158.0	303.5	19.0	2022	Oil
PL1003	Mistral N	60.00 %	20 %	4.2	10.2	22.8	2.0	2021	Gas-C
	Mistral S	60.00 %	30 %	4.2	13.8	34.8	4.1	2021	Gas-C
PL910	Carolina	16.67 %	17 %	0.4	1.9	4.1	0.3	2021	Oil
PL153	Hamlet	12.00 %	72 %	1.7	2.0	2.6	1.5	2020	Oil
PL973	Jerv	30.00 %	51 %	10.8	15.9	21.6	8.1	2020	Gas-C
	Ilder	30.00 %	32 %	7.5	17.1	27.3	5.5	2020	Oil
	Mår	30.00 %	19 %	8.7	21.1	35.1	4.0	2021	Oil
Total prospective volumes					**269**		**52**		

5.1. PL093 – SPRINGMUS, EAST FLANK

Several exploration targets exist in the Draugen licences. The targets include Springmus and East Flank. In November 2019, the Skumnisse prospect was tested dry. The remaining prospects and some new leads will be updated by the newly acquired well data and evaluated as drilling candidates.

5.2. PL1001 – DRAUGEN NE

PL1001 contains the Draugen NE prospect, in the same Rogn Formation play as the Draugen field. The licence, awarded as part of the APA 2018 round and operated by ConocoPhillips, has a "Drill or Drop" decision by March 2021.

5.3. PL958 - RIALTO

The PL958 licence to the east of Draugen on the Trøndelag Platform contains several prospects. The most promising is the Rialto prospect, identified by a typical sand signature with significant lateral extent in the 2D seismic data. The play is the same as on Draugen, with reservoir in the Late Jurassic Rogn Formation. The source is likely the Spekk Formation, charging Rialto via spill from Draugen. Charge is the main risk. The licence is operated by OKEA, after taking over working interest from Shell, In June 2019, the licensees voted to acquire 3D seismic by prefunding a multi-client project. A fast track data delivery is done in December 2019, while the final data are delivered in June 2020. The new data set will provide basis for a full remapping of the license.

5.4. PL1003 - MISTRAL

The PL1003 licence in the Norwegian Sea was awarded to OKEA (60%, operator) and Wellesley Petroleum (40%) in the APA 2018 round. The Mistral N prospect is based on a possible hydrocarbon accumulation up-flank of the 6406/3-1 well. The Mistral S prospect is based on a similar hydrocarbon column being also present in the southern part of the horst block. The main risk for both prospects is retention of commercial volumes in a likely blown-trap scenario. The licensees have a one-year 'Drill or Drop' decision deadline, expiring in March 2020.

5.5. PL910

The Kathryn prospect was drilled in the neighbouring licence to Yme in October 2019. The well was dry, most likely due to failure in migration. The PL 910 license contains also the Carolina prospect, which will be reevaluated after the dry Kathryn well. During 2020, the licensees will decide whether to continue or relinquish the license based on the reevaluation.

5.6. PL153 - HAMLET

The Hamlet prospect, within the Gjøa licence, is a Cretaceous prospect, similar to the nearby Duva and Agat discoveries. The reservoir consists of turbidite flows originating from the southeast. The well has been sanctioned by the Gjøa licensees, and the site survey was acquired in 2019 with drilling subject to rig availability. Hamlet has a possible rig slot in 2020, but can slip into 2021 depending on rig schedule. Hamlet is believed to be connected with the Agat (35/9-3 T2) discovery to the north by a saddle. Hence, a high COS is assumed.

5.7. PL973 – JERV, ILDER, MÅR

The Ilder and Jerv prospects were sanctioned for drilling in December 2019. The aim is drill back-to-back in Q4 2020. The Ilder prospect is upflank from the 15/12-2 well, in the Hugin and Ula formations, on a structural 4-way closure. The main risk for Ilder in migration. The Jerv prospect is a continuation of the Fleming field on the UKCS. It is in the Paleocene Ty/Maureen Formation. The main risk is depletion from production of Fleming. The Mår prospect is still regarded as immature for drilling, as it will be further derisked by the ongoing work program. Mår is located in a Late Jurassic growth wedge on the flank of a structural high. This play is not proven in the area.

6 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 or when facility lease expires. The company has used a long-term inflation assumption of 2 percent, a long-term exchange rate of 8.0 NOK/USD, and a long-term oil price of 65 USD/bbl (real 2019 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 remaining risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the reserves. Low oil prices may force the licensees to close down producing fields early and lead to lower production. Similarly, better-than-expected reservoir performance or higher oil prices may extend the lifetime of the fields beyond what is currently assumed.

Erik Haugane
CEO

OKEA is an oil company contributing to the value creation on the Norwegian Continental Shelf with cost effective development and operation systems.

OKEA ASA

Ferjemannsveien 10
7042 Trondheim

www.okea.no