OKEA Annual Statement of Reserves and Resources 2019 – Status 01.03.2019

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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 AS 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, which again is based the *SPE Guidelines for the reserves and resources reporting, SPE 2007.*

The overview in this document is an early version of the ASR 2019, with cut-off date 01.03.2019. It represents a status update to the ASR 2018 (cut-off date 31.12.2018), taking into account changes to the resource base since that date, including effects of production in January & February 2019.

2 Classification of Reserves and Contingent Resources

OKEA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE's) Petroleum Resources Management System (PRMS). 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

Table 1.

The reserves and resources estimates are for most cases in line with the RNB (Revised National Budget) reporting to the Norwegian Authorities, which uses the classification system of the Norwegian Petroleum Directorate. A comparison between this and the SPE PRMS is shown in Table 2.

For completeness, OKEA also reports the contingent and prospective resource estimates. Both categories are reported in line with the SPE PRMS.

Table 1: SPE reserves and resources classification system

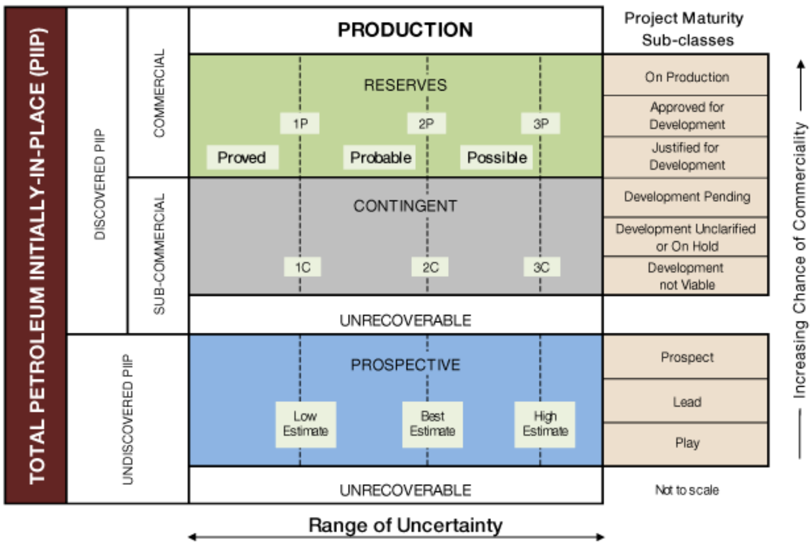

Table 2: SPE and NPD classification systems compared

SPE PRMS 2007	
	Project Maturity sub-classes
Production	
RESERVES	On Production
	Approved for Development
	Justified for Development
CONTINGENT RESOURCES	Development Pending
	Development unclarified or on Hold
	Development not Viable
Unrecoverable	
PROSPECTIVE RESOURCES	Prospect
	Lead
	Play

NPD 2001		
Resource class	Project status category	
Production	S	Sold and delivered
RESERVES	1	In production
	2 F/A	Approved PDO
	3 F/A	Licencees have decided to recover
CONTINGENT RESOURCES	4 F/A	In the planning phase
	5 F/A	Recovery likely but undecided
	7 F/A	Not yet evaluated
	6	Recovery not very likely
UNDISCOVERED RESOURCES	8	Prospect
	9	Lead and Play

3 Reserves

OKEA AS has reserves distributed in 4 fields, listed in Table 3. The Project Status Category describes the maturity for each of the fields and projects. Reserves are essentially volumes in producing assets or sanctioned projects in proven accumulations, i.e. "Approved for development" indicates field developments for which the Plan for Development and Operations (PDO) is approved by the Ministry of Petroleum and Energy.

Table 3: OKEA asset portfolio with reserves

Field/Project	Interest (%)	Operator	Project Status Category	Comment
Draugen field	44.56%	OKEA	On production	Main proportion 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. The production numbers and costs are for the most part in line with the 2019 RNB.

For economic evaluations, the average future oil price assumption is $70/bbl, with a long-term currency rate of 7.50 NOK/USD. 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.

The following conversion factors are used:

Oil -	1 Sm^3 = 6.29 bbl
	1 Sm^3 = 1 Sm^3 o.e.
Gas -	1000 Sm^3 gas = 1 Sm^3 o.e.
	1 Sm^3 = 35.3 Scf
NGL -	1 tonne NGL = 1.9 Sm^3 o.e.
	1 Sm^3 o.e. = 6.29 boe

3.1. TOTAL RESERVES ESTIMATES

OKEA's net proven reserves (1P/P90) as of 01.03.2019 are estimated at 45.6 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 54.6 million barrels of oil equivalents. The reserves figures are adjusted for the effects of production in January and February 2019. The split between liquid and gas and between the different subcategories are given in Table 4. The reserves numbers are verified by a third party reserves certification performed by AGR Petroleum Services.

Table 4: OKEA AS 1P and 2P reserves as of 01.03.2018

Asset	Interest (%)	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
		(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Reserves – On Production											
Draugen	44.56%	58.3	0.9	0.0	59.3	26.4	66.0	1.1	0.0	67.1	29.9
Gjøa	12.00%	4.2	20.9	48.4	73.5	8.8	7.3	28.3	65.6	101.1	12.1
Ivar Aasen	0.554 %	73.8	3.8	12.5	90.1	0.5	103.9	4.9	16.4	125.2	0.7
Total Net oe (as of 31.12.2018)						35.7					42.7
Production						-1.0					-1.0
Total Net oe (as of 01.03.2019)						34.7					41.7
Reserves – Approved for Development											
Yme	15.00%	51.9	0.0	0.0	51.9	7.8	63.8	0.0	0.0	63.8	9.6
Gjøa - P1	12.00%	8.2	5.1	12.0	25.4	3.0	8.8	5.4	12.6	26.9	3.2
Total Net oe (as of 01.03.2019)						10.8					12.8
Reserves – Justified for Development											
IAA - infill	0.554%	6.0	0.3	1.0	7.3	0.0	11.9	0.5	2.1	14.5	0.1
Total Net oe (as of 01.03.2019)						0.0					0.1
Reserves –Total											
OKEA Net oe (as of 31.12.2018)						46.5					55.6
OKEA Net oe (as of 01.03.2019)						45.5					54.6

For completeness, the corresponding 3P/P10 estimate of net OKEA reserves is 66.6 mmboe.

Production effects that were accounted for are i) difference between prognosed and actual production in 2018, ii) production in January and February 2019. These corrections amount to 0.02 mmboe, 0.33 mmboe and 0.66 mmboe for Ivar Aasen, Draugen and Gjøa, respectively.

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 5 shows how the volumes have changed since ASR 2018 (31.12.2018). Production stems from the Ivar Aasen, Gjøa and Draugen assets. The project maturation is related to Gjøa P1.

Table 5: Reserves Development 31.12.2018 to 01.03.2019

Reserves Development								
Net attribute mmboe	**Developed Asset**		**Under Development**		**Non-developed**		**Total**	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance year end 2018	35.7	42.8	7.8	9.6			43.5	52.4
Production	-1.0	-1.0					-1.0	-1.0
Acquisition / disposals								
Extensions and discoveries								
New developments								
Revisions of previous estimates								
Projects matured			3.1	3.2			3.1	3.2
Balance as of 01.03.2019	34.7	41.8	10.9	12.8			45.6	54.6

3.3. DESCRIPTION OF RESERVES

The following chapter 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, and 30 km east of the Njord field (Figure 1).

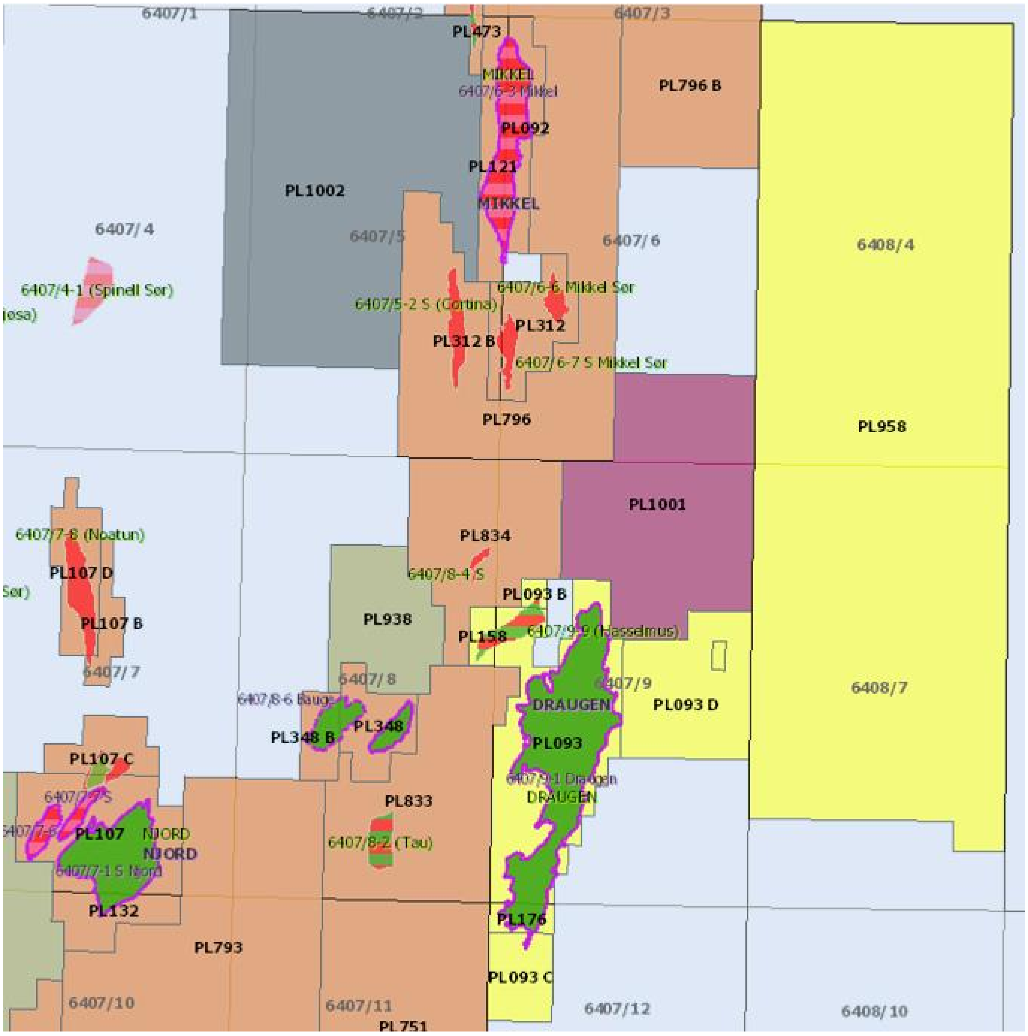

Figure 1: Draugen field location and adjacent area (Norwegian Sea). OKEA operates licences highlighted in yellow and is partner in PL1001

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. 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 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 are in operation, in addition to 2 subsea water injectors. The platform wells are gas lifted, while the subsea wells are produced with a subsea booster pump to lower the tubing head pressure.

Status

The current production on Draugen is in the order of 23 000 bbl of oil and nearly 180 000 bbl of water per day. 110 000 bbls of water is reinjected to the reservoir, while the rest is discharged to sea with an oil in water of approximately 20 ppm.

All platform wells are producing except A-5, which is shut in due to high water cut. All subsea wells are producing, but mostly on cyclic production in order to reduce water cut of the system. Currently, a campaign to change out the Christmas trees on A-2 and A-3 is planned for the first half of 2019. Production is continuously analysed and optimized by a production management team.

The reserves estimates are based on the RNB 2019 submission by the former operator, Shell. Production from mid-2021 onwards, however, was classified as contingent to sanction of a long-term power project in RNB 2019 (2C resources) which would justify a field lifetime extension to 2027. As the licence has now taken an FID for this project, these volumes are now included in the 2P reserves. In a similar fashion, production from economic field lifetime extension to 2035, enabled by cost-cutting initiatives on Draugen and a feasibility study by Shell in 2018, were included in the 2P reserves.

The OKEA working interest on Draugen is 44.56% and the net OKEA P2/P50 reserves are 29.6 mmboe. The other licencees are Petoro AS (47.88%) and Neptune Energy Norge AS (7.56%). 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 on Draugen are related to the Hasselmus discovery and two infill targets, as described in Section 0.

3.3.2. Gjøa (PL153)

The Gjøa field lies is a field in the northern part of the North Sea, 50 kilometres northeast of the Troll field (Figure 18). The water depth in the area is 360 meters.

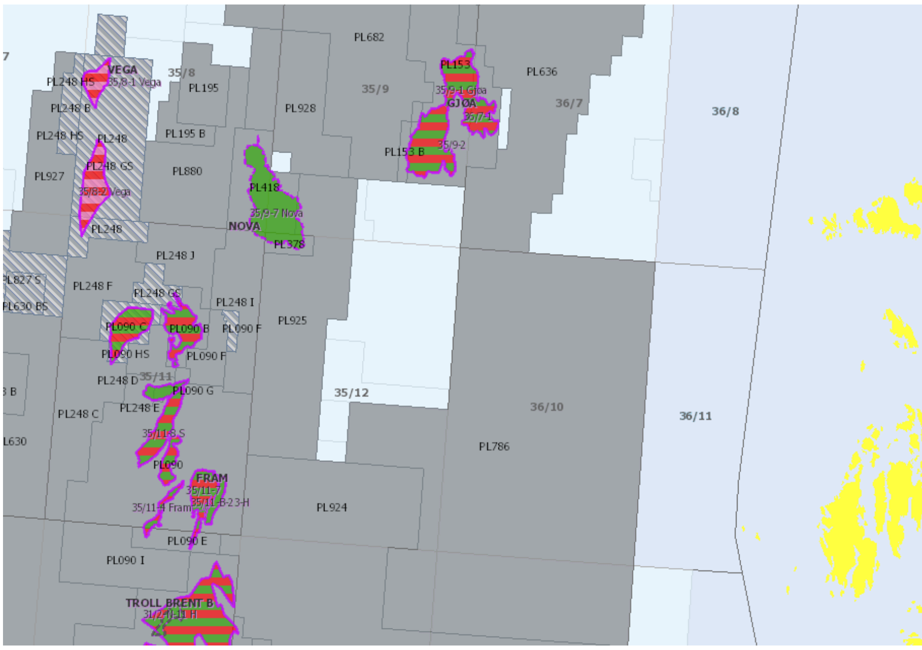

Figure 2: Gjøa field location (North Sea)

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 0.4 bcf/d and a declining oil rate, currently at 19 000 bbl/d. All wells are on stream except the C-2 oil well, which has unresolved lift problems. The main deferment in 2018 was related to St. Fergus terminal maintenance in September. However, the uptime is high, with an average of 92% in 2018.

The reserves estimate for Gjøa is based on the RNB 2019 submitted by the operator, Neptune Energy, plus reserves related to the P1 redevelopment project which was sanctioned by the licensees in February 2019. The OKEA working interest on Gjøa is 12% and the net OKEA 2P/P50 reserves from Gjøa and P1 are 14.7 mmboe. The other licensees on Gjøa are Neptune Energy Norge AS (operator, 30%), Petoro AS (30%), Wintershall Norge AS (20%) and DEA Norge AS (8%). Contingent resources on Gjøa are related to the B1 and the recent Agat discovery in 35/9-3, as discussed in Section 4.

Appraisal of the Agat discovery is being planned (Hamlet); the prospective volumes are addressed in chapter 5.

Gjøa is already host for the Vega field, and tie-in activities for the Nova field are planned during 2019-2020.

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 3), 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.

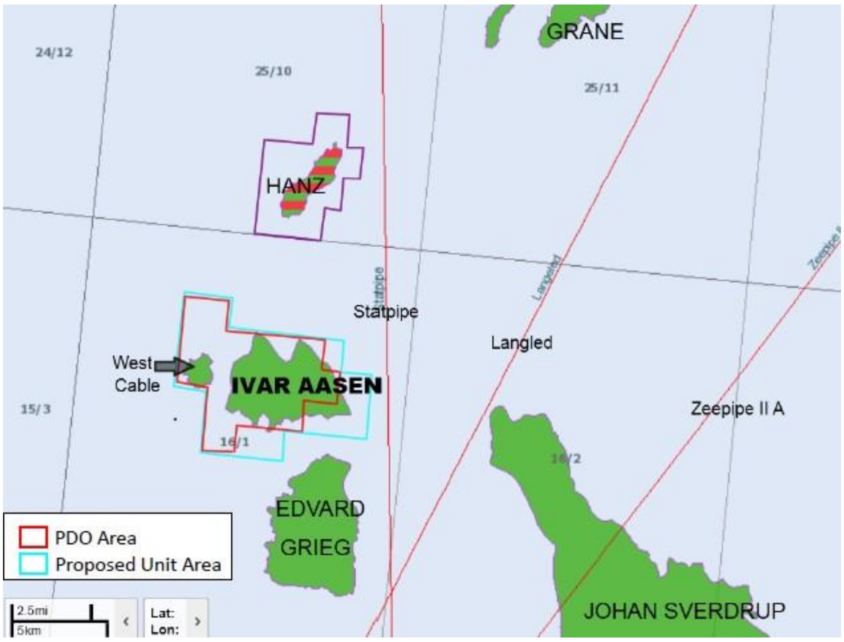

Figure 3: Ivar Aasen and West Cable location map, North Sea

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 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.

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.

Status

Production from Ivar Aasen started in late 2016, and the current production rate is approximately 50 000 bbl/d, together with some associated gas. 2018 production was slightly lower than expected, mainly due to reduced gas turbine capacity at Edvard Grieg in March-April. Challenges related to water injection in the eastern part of the field have been mitigated by introducing two additional injectors, D-6 and D-7, which came on stream in the summer of 2018. In general, the field reserves are slightly increased since the PDO, although the West Cable resources have been significantly reduced.

The reserves estimate for Ivar Aasen are based on RNB 2019. OKEA AS holds a 0.554% working interest in the licence and the net OKEA 2P/P50 reserves from Ivar Aasen and Infill drilling are 0.75 mmboe. 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 (Figure 4), 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 submitted by the new operator, Talisman, was approved. 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, OKEA initiated the "Yme New Development" project and in 2018 a new PDO was approved by the authorities.

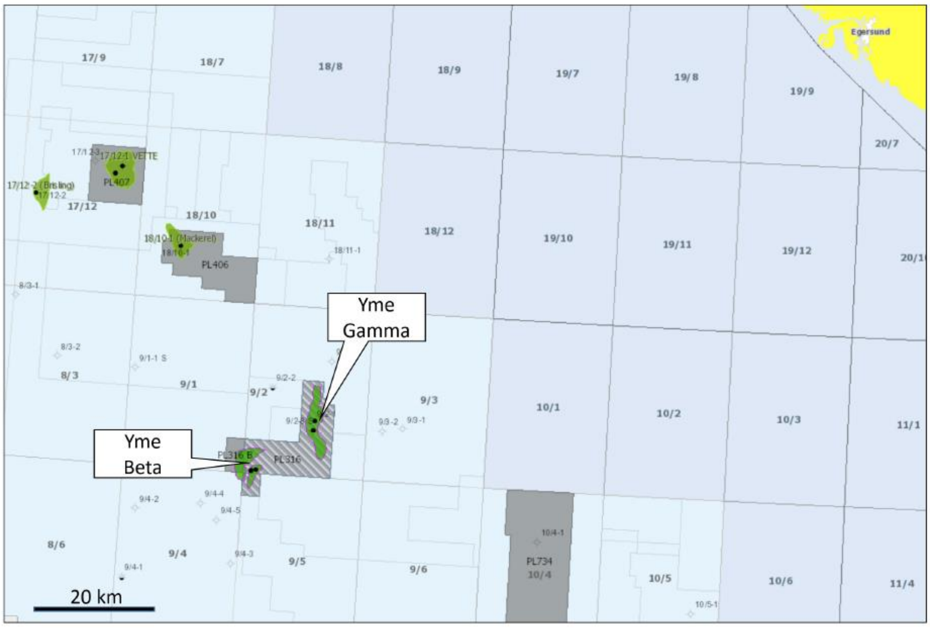

Figure 4: Yme Gamma and Beta location map, North Sea

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

The Yme field will be developed with a jack-up MOPU equipped with processing facilities. This will be connected to the existing MOPUSTOR tank, left by the previous operator, 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 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 38,000 bbl/d.

Current offshore work is on the caisson structure, as preparation for the support structure installation. Onshore work includes the well head module fabrication and piping fabrication. The wellhead module will be installed in October 2019, while the production unit Maersk Inspirer will start hook-up and commissioning in December 2019.

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 the Gamma wells is scheduled for 2020 while Beta wells are planned for 2021-22.

The reserves on Yme are based on RNB 2019, which again are based on the DG3 / FID profiles for the field. OKEA AS holds 15 percent in Yme and the net OKEA 2P/P50 reserves are 9.6 mmboe. 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 FID (Final Investment Decision). OKEA holds contingent resources in several licences. Table 6 shows the total overview of the contingent resources, and the following chapter gives a brief introduction to the Grevling and Storskrymten fields and the other contingent resources.

Table 6: Total contingent resources

As of 01.03.2019	Interest	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
		Low	Base	High	Low	Base	High
Hasselmus	44.56%	12.6	14.7	16.7	5.6	6.5	7.5
Hasselmus - Lifetime to 2038	44.56%	6.5	8.0	9.3	2.9	3.6	4.2
Draugen - Infill Ø	44.56%	1.7	4.1	6.2	0.7	1.8	2.7
Draugen - Infill Æ	44.56%	2.2	5.6	8.3	1.0	2.5	3.7
Gjøa - B1 and Agat	12.00%	0.1	2.4	3.6	0.0	0.3	0.4
Grevling	55.00%	21.5	32.6	47.5	11.8	17.9	26.1
Storskrymten	78.57%	2.5	9.4	16.3	2.0	7.4	12.8
Yme - 5 year life extension	15.00%	7.1	8.8	11.1	1.1	1.3	1.7
Total Contingent Volumes (current WI)					**25.1**	**41.3**	**59.1**
Grevling - reduced WI *	35.00%	21.5	32.6	47.5	7.5	11.4	16.6
Storskrymten - reduced WI *	50.00%	2.5	9.4	16.3	1.2	4.7	8.1
Total Contingent Volumes (reduced WI)					**20.1**	**32.1**	**44.9**

*Chrysaor has the right to acquire an additional 20% of OKEA's participating interest in PL038 D and 28.57% of OKEA’s participating interest in PL974, in the event that the PL 038D management committee decides to submit a BOV Decision. Option to be exercised within the earliest of i) 1 June 2019, or ii) 14 days after notice of BOV Decision has been submitted to the MPE.

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 5), 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 by the end of 2019, 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. The PL973 exploration licence, directly to the south, is also operated by OKEA.

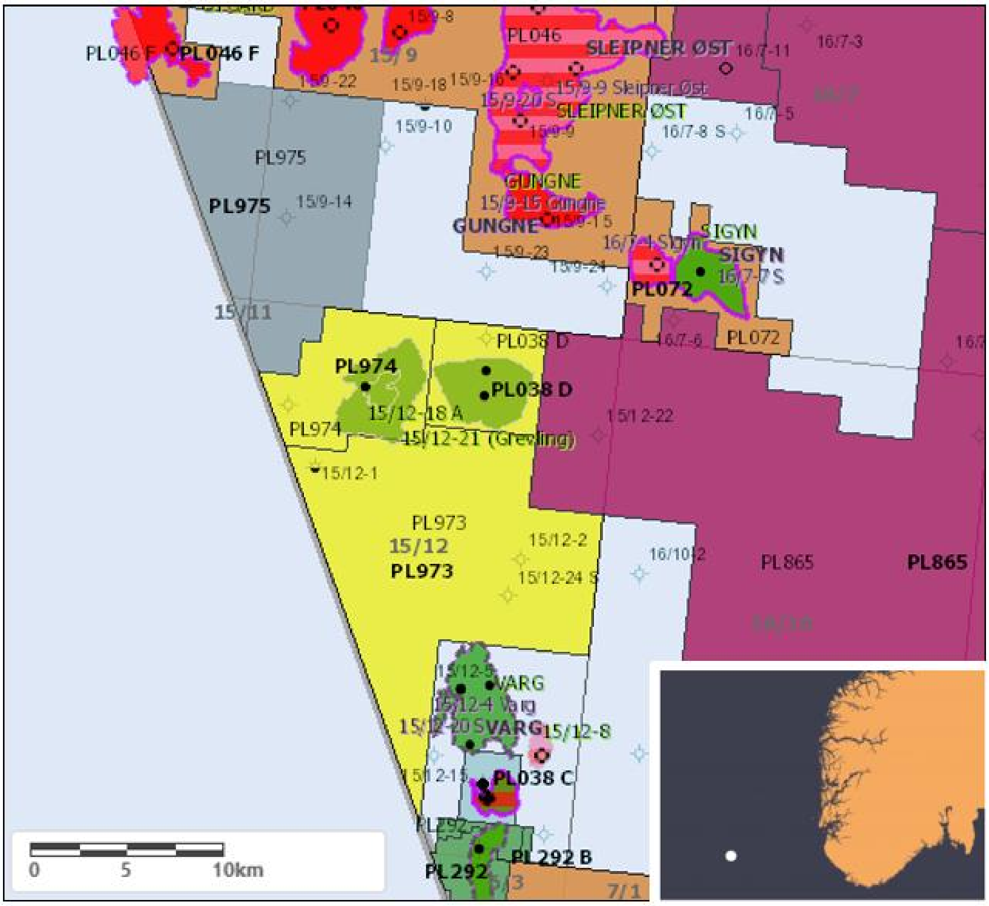

Figure 5: Grevling and Storskrymten location map, North Sea

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 Formation.

Development

The licensees have decided that a standalone development with a mobile production unit (MOPU), as illustrated in Figure 6, is the preferred concept.

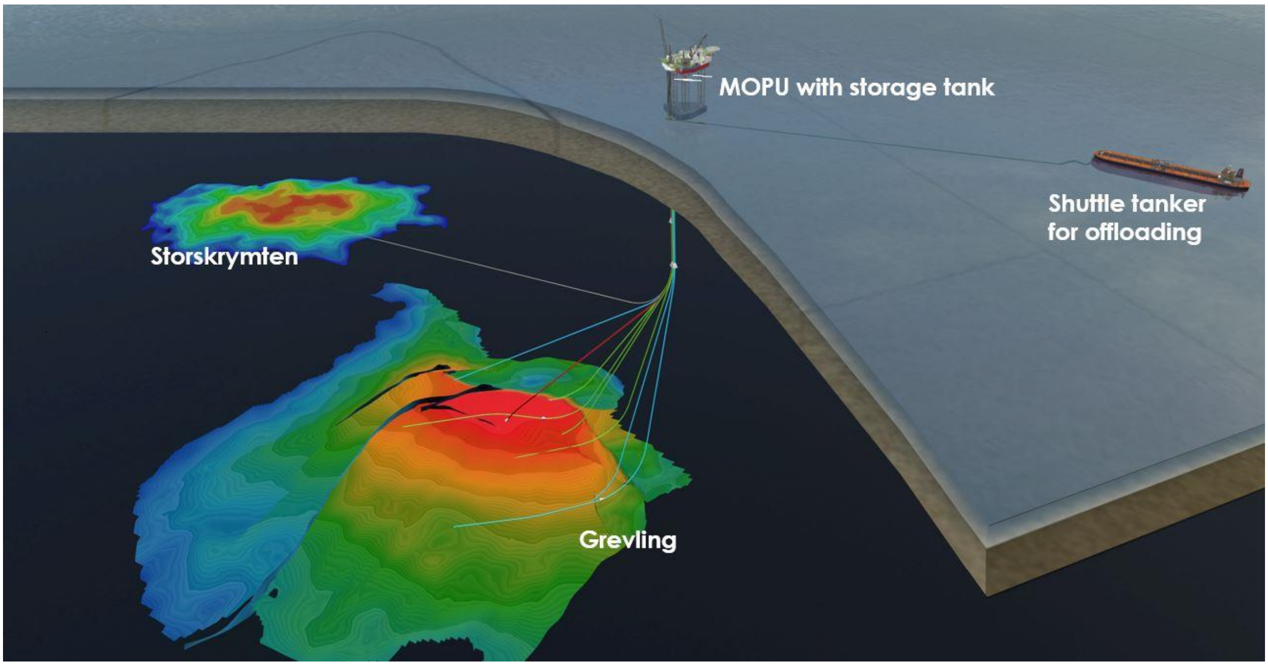

Figure 6: Sketch of MOPU concept

Status

The Grevling project is moving towards a BoV (decision to continue) in Q4 2019, and planned production start-up late 2022/early 2023. Storkrymten 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.

OKEA is the operator for Grevling and holds a 55% working interest in the field, with Petoro (30%) and Chrysaor Norge (15%) as licence partners. As part of the 2018 SPA with OKEA, Chrysaor has the right to increase their working interest to 35%, reducing OKEA's share to 35% in the event that the PL 038D management committee decides to submit a BOV Decision (option to be exercised within the earliest of i) 1 June 2019, or ii) 14 days after notice of BOV Decision has been submitted to the MPE). OKEA also operates Storskrymten with a 78.57% working interest, together with Chrysaor Norge (21.43%) as partner. Here, Chrysaor has a similar right to increase their working interest to 50%, reducing OKEA's share to 50%.

4.2. DRAUGEN INFILL DRILLING

Infill drilling locations are being evaluated to increase recovery from the main Draugen field; two infill well locations are included as contingent resources, one of which is planned to be evaluated by a pilot well in 2019-20.

4.3. DRAUGEN HASSELMUS

The main contingent resources on Draugen are located in the Hasselmus discovery. This includes both gas and oil, of which the gas is being evaluated for development. This gas will replace the planned gas import for fuel, and potentially also imply export of gas. The reduced OPEX from this gas source can extend the economic lifetime of the Draugen platform for at least three years; resources related to this are included as contingent resources.

4.4. GJØA - B1 WELL AND AGAT

A change-out of the gas lift valve by LWI is planned for the B-1 well in April 2019. If successful, the measure is expected to increase the net OKEA volumes by 0.13 mmboe.

Neptune reported in May 2018 estimated in-place volumes related to the Agat discovery (well 35/9-3T2). Assuming a recovery factor of 10%, net volume to OKEA is 0.15 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. Net volumes range from 1.1 – 1.7 mmboe.

5 Prospective resources

Prospective resources are defined as potentially recoverable from undiscovered accumulations. Table 7 shows the total overview of these resources. One of the major prospects is located in the PL958 licence which was transferred from A/S Norske Shell to OKEA AS on 31 January 2019. Four other licences were awarded in the APA 2018 round in January 2019. There has therefore been an increase from 174 to 352 mmboe unrisked prospective resources since ASR2018.

Table 7: Prospective Resources

PL	Prospect	OKEA WI%	Prob. of Discovery	Net unrisked resources (mmboe)			Net base risked resources (mmboe)	Possible first well	Main HC phase
				Low	Base	High			
PL093*	Skumnisse	44.56%	30%	1	11	27	3	2019	Oil
	Springmus E	44.56%	37%	0	3	8	1	2020	Oil
	Springmus W	44.56%	33%	0	1	4	0	2020	Oil
	East Flank	44.56%	35%	0	1	3	0	2020	Oil
PL1001	Draugen NE	20.00%	22%	5	24	66	5	2021	Oil
PL958*	Rialto	50.00%	12%	47	158	303	19	2022	Oil
PL1003*	Mistral N	60.00%	70%	15	49	79	34	2020	Gas-C
	Mistral S	60.00%	40%	15	49	117	20	2021	Gas-C
PL910	Kathryn	16.67%	27%	1	4	8	1	2019	Oil
PL153	Hamlet	12.00%	56%	1	2	4	1	2020	Oil
PL973*	Jerv	30.00%	57%	10	18	26	10	2020	Oil
	Ilder	30.00%	34%	6	12	17	4	2021	Oil
	Mår	30.00%	18%	9	21	35	4	2020	Oil
	Total prospective volumes				**352**		**103**		

5.1. PL093 – SKUMNISSE, SPRINGMUS, EAST FLANK

Several exploration targets exist in the Draugen licence. The targets include the already defined Springmus, East Flank and Skumnisse prospects identified by Shell. The main differentiator from Shell's work is the incorporation of the 2016 depth conversion and further geophysical analysis, which improved the definition of all prospects.

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 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, awarded as part of the APA 2018 round, has an "Acquire 3D seismic or drop" decision in June 2019.

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, based on the applicants' interpretation that the 6406/3-1 discovered gas condensate in the Jurassic Garn Formation in the Mistral N horst block west of the Tyrihans Field. Interpretation of logs and a DST from the well indicate a significant in-place volume upflank of the well with a high expected recoverability. The Mistral S prospect is based on a similar hydrocarbon column being also present in the southern part of the horst block. The licensees have a one-year 'Drill or Drop' decision deadline.

5.5. PL910 - KATHRYN

The Kathryn prospect is planned to be drilled in the neighbouring licence to Yme in Q2-3 2019. A discovery in this structure would be developed through the Yme infrastructure. The prospect lies a few kilometres East of Yme Gamma. It is the same play as Yme, with reservoir in the Mid Jurassic Sandnes Formation, sourced by the Tau Formation. The main risk is timing between trap formation and migration.

5.6. PL153 - HAMLET

The Hamlet prospect, within the Gjøa licence, is a Cretaceous prospect, similar to the nearby Cara discovery. The reservoir consists of turbidite flows originating from the southeast. The well has been sanctioned by the Gjøa licensees, and the site survey will be acquired in 2019 with drilling subject to rig availability. Most likely, Hamlet is drilled in 2020. 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 prospects in PL973, awarded in the APA 2018 round, are being evaluated towards a Drill or Drop decision within two years. Jerv and Ilder, prospects in the Paleocene Ty Formation and Mid-Upper Jurasic Hugin Formation respectively, have been fully assessed and the Jerv prospect is considered mature enough to drill. Mår is also a Hugin Formation prospect.

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 7.50 NOK/USD, and a long-term oil price of 70 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