OKEA Annual Statement of Reserves and Resources 2018

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1 Introduction

The Annual Statement of Reserves and Resources 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 a status as of 31.12.2018.

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". 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

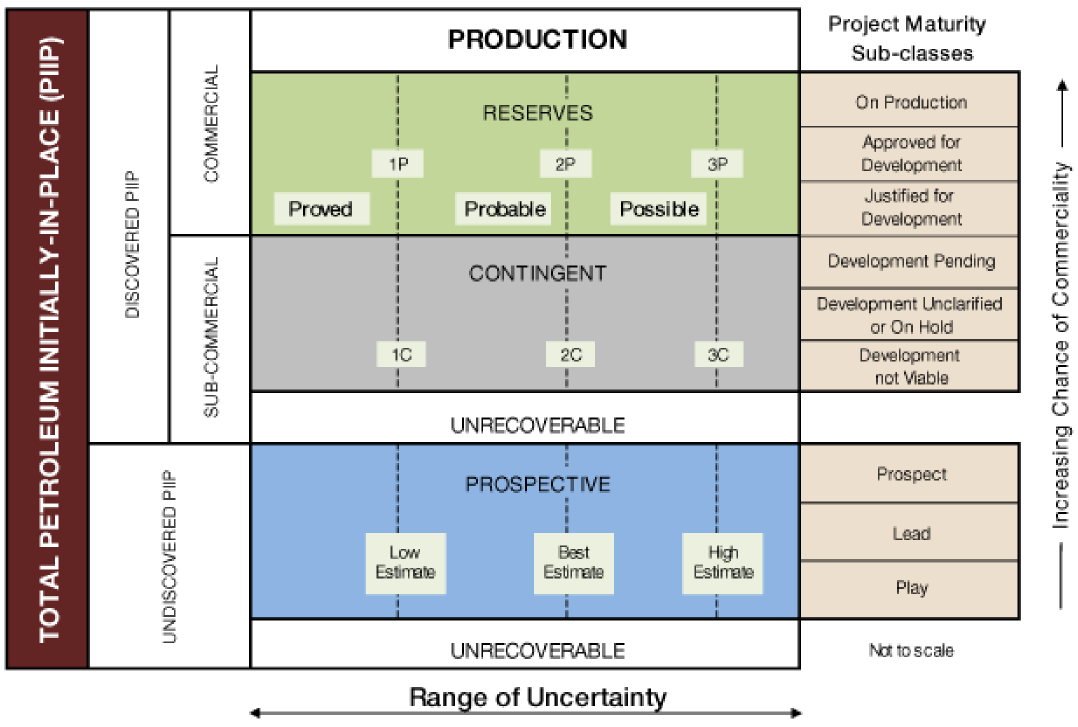

Table 2: SPE and NPD classification systems compared

SPE PRMS 2007	
Production	Project Maturity sub-classes
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

Field/Project	Interest (%)	Operator	Project Status Category	Comment
Draugen field	44.56%	OKEA	On production	Main proportion of OKEA reserves
Gjøa field	12 %	Neptune	On production	
Ivar Aasen field	0.554%	Aker BP	On production	
Yme field	15 %	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. In the case of the Draugen field, however, some volumes have been moved from contingent resources to reserves since the 2019 RNB figures were submitted.

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, 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 31.12.2018 are estimated at 43.5 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 52.4 million barrels of oil equivalents. 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 31.12.2018

As of 31.12.2018	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	1.1	0.0	59.4	26.5	66.0	1.1	0.0	67.1	29.9
Gjøa	12%	4.2	20.2	48.4	72.8	8.7	7.3	28.1	65.6	101.0	12.1
Ivar Aasen	0.554 %	73.8	3.8	12.5	90.1	0.5	103.9	4.9	16.4	125.1	0.7
Total Net oe						35.7					42.7
Reserves – Approved for development											
Yme	15%	51.9	0.0	0.0	51.9	7.8	63.9	0.0	0.0	63.9	9.6
Total Net oe						7.8					9.6
Reserves – justified for development											
Ivar Aasen	0.554 %	6.0	0.6	2.1	8.6	0.0	11.9	0.6	2.1	14.6	0.1
Total Net oe						0.0					0.1
Reserves – TOTAL											
OKEA Net oe						43.5					52.4

For completeness, the corresponding 3P/P10 estimate of net OKEA reserves is 63.2 mmboe.

3.2. DEVELOPMENT OF RESERVES

OKEA's reserves and resources are continually matured through field development work, improvement of technical sub surface models, acquisitions and production. Table 5 shows how the volumes have changed during the last year.

Table 5: Reserves Development 31.12.2017 to 21.12.2018

Reserves Development								
Net attribute mmboe. Calendar years, reporting as of year end 2018	Developed Asset		Under Development		Non-developed asset		Total	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance year end 2017	0.6	0.8	7.9	9.7			8.5	10.5
Production	-0.9	-0.9					-0.9	-0.9
Acquisition / disposals	35.9	42.8					35.9	42.8
Extensions and discoveries								
New developments	0.0	0.1					0.0	0.1
Revisions of previous estimates	0.0	-0.01	-0.1	-0.1			-0.1	-0.1
Projects matured								
Balance (current ASR) as of 31.12.2018	35.7	42.8	7.8	9.6			43.5	52.4

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

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).

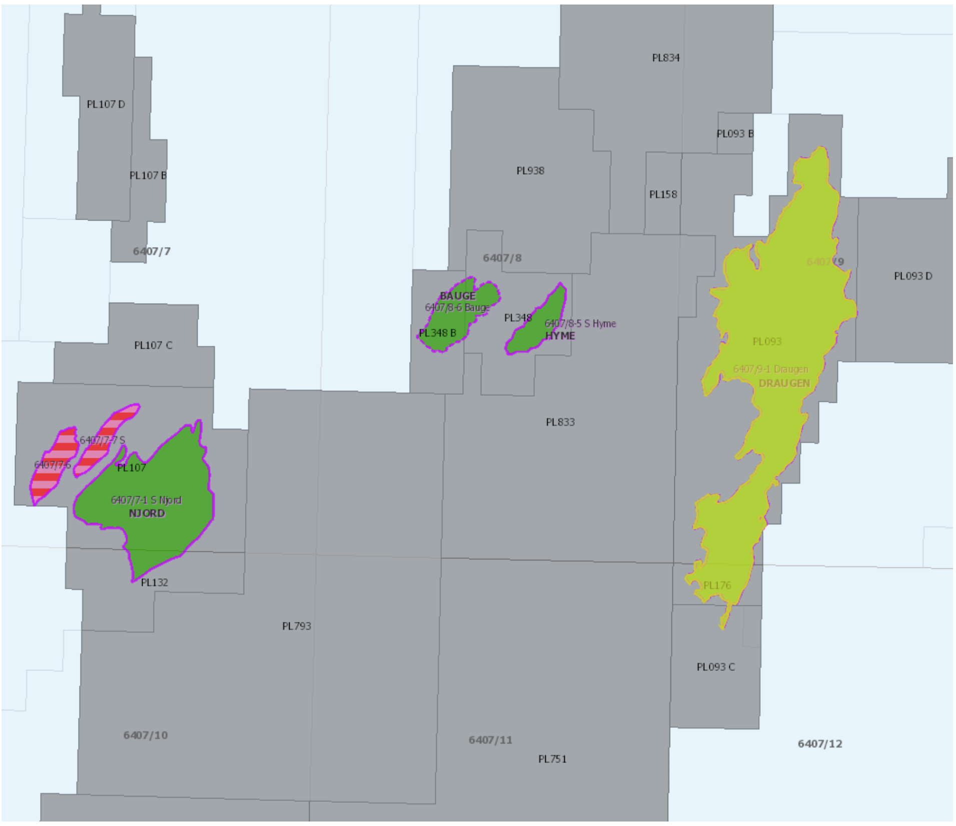

Figure 1: Draugen field location, Norwegian Sea

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 February-March 2019. The main operational challenges are related to operations of the subsea pump, and limited water handling capacity. 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 as per PRMS) which would justify a field lifetime extension to 2027. As the licence is now ready to take DG3 for this project, we now consider these volumes as 2P reserves. In addition, due to cost-cutting initiatives on Draugen and a lifetime extension feasibility study by Shell in 2018, the economic field lifetime has been further extended to 2035.

The OKEA working interest on Draugen is 44.56%, and the net OKEA 2P/P50 reserves are 29.9 mmboe. The other licencees are Petoro AS (47.88%) and Neptune Energy Norge AS (7.56%).

Several infill and exploration well locations are being investigated, both within and outside the main structure (Dansemus, East Flank, Skumnisse, Springmus etc). The strategy is to drill low cost appraisal wells to confirm and quantify these volumes before sanctioning production wells. The volumes have been included as prospective resources in this document.

3.3.2. Gjøa

Gjøa is a field in the northern part of the North Sea, 50 kilometres northeast of the Troll field (Figure 2). The water depth in the area is 360 meters.

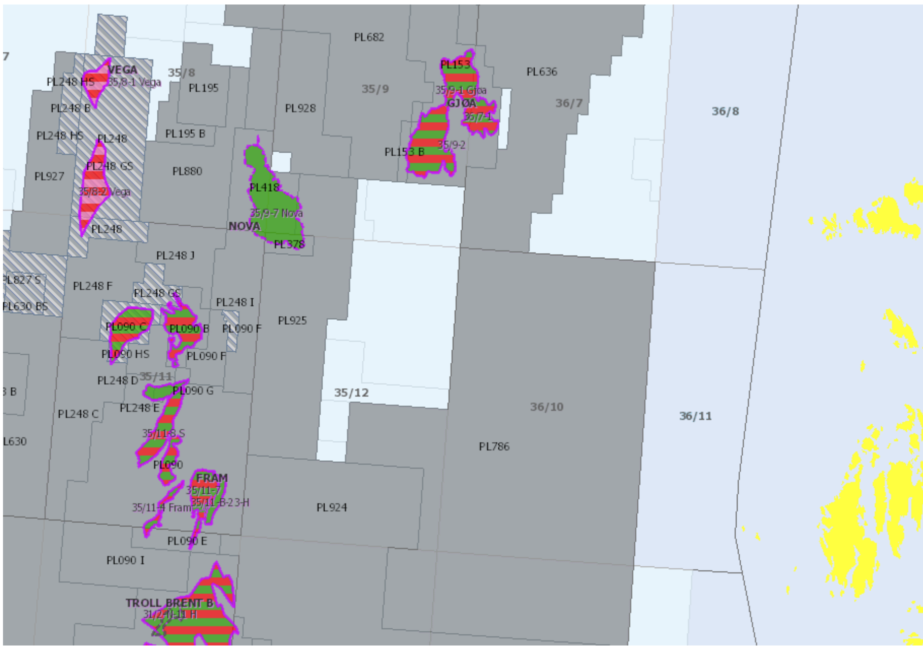

Figure 2: Gjøa field location, North Sea

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 5680 bbl/d (Dunlin) 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. The OKEA working interest on Gjøa is 12%, and the net OKEA reserves ranges from 8.7-17.0 mmboe, with a P2/P50 of 12.1 mmboe. The other licencees on Gjøa are Neptune Energy Norge AS (operator, 30%), Petoro AS (30%), Wintershall Norge AS (20%) and DEA Norge AS (8%).

The main field development project on Gjøa, the P1 redevelopment, is expected to pass FID in Q1 2019. In addition, appraisal of the Agat discovery is being planned (Hamlet). However, some of the P1 contingent volumes are undiscovered, and Agat is considered too small to be included as contingent resources. Hamlet prospectivity is 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. Final negotiations on tie-in of the Cara field are also ongoing, prior to a planned Cara FID in February 2019.

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 licenses and have been unitized into the Ivar Aasen Unit.

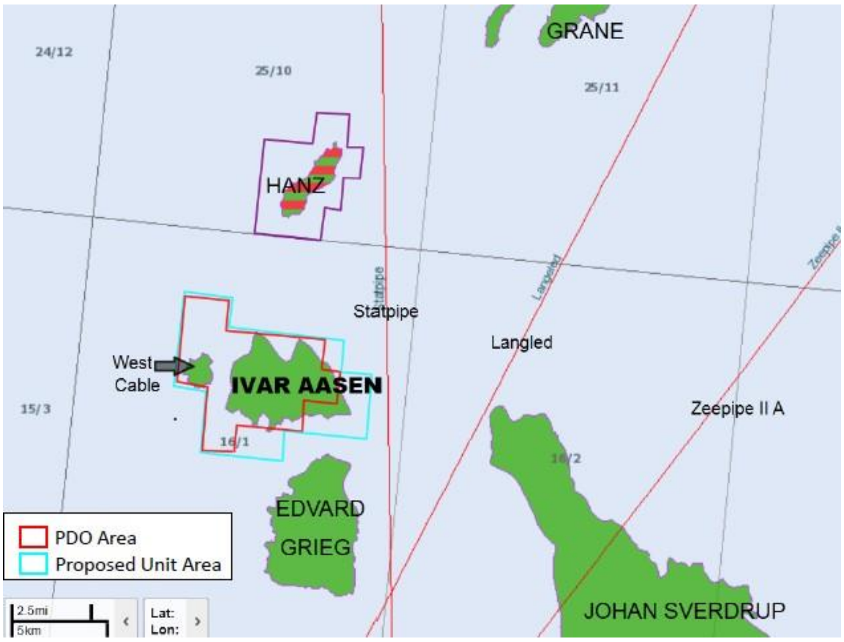

Figure 3: Ivar Aasen and West Cable location map, North Sea

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 at 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. The 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. 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.

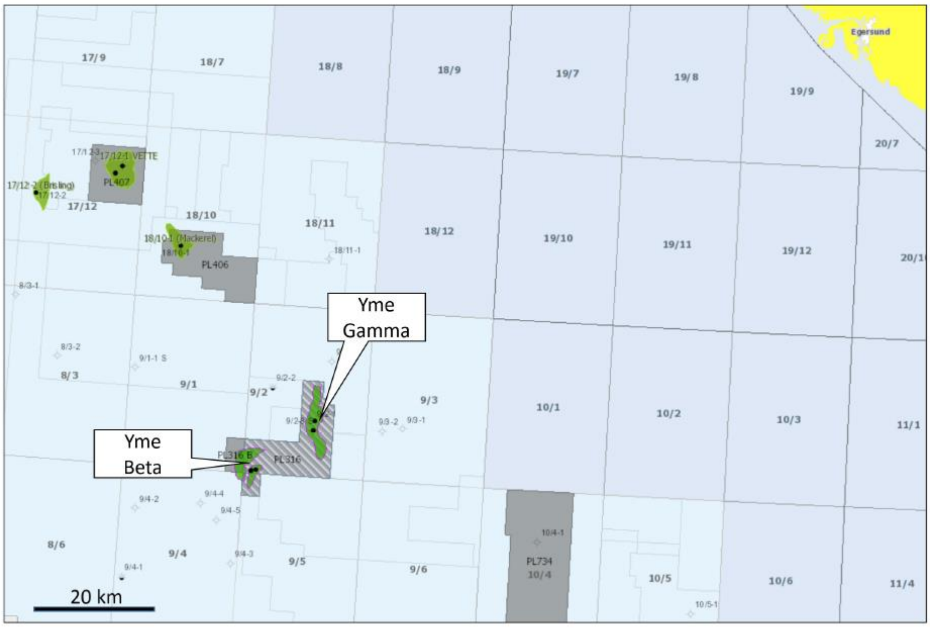

Figure 4: Yme Gamma and Beta location map, North Sea

Discovery

The Yme field was discovered in 1987 by the 9/2-1 well in the Gamma structure, with test oil rate of 4145 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 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 a 15% working interest in Yme. The remaining interests are held by Repsol (55%), Lotos (20%) and KUFPEC (10%).

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 licenses. Table 6 shows the total overview of the contingent resources, and the following chapter gives a brief introduction to the Grevling field and the other contingent resources.

Note that volumes from Draugen Dansemus and Agat appraisal are not included, as the volume estimates are too immature. However, the Hamlet Prospect and Draugen Appraisal are included in the Prospective Resources.

Table 6: Total contingent volumes

Name of project	Interest	Net Oil equivalents (million boe)		
		Low	Base	High
Hasselmus Gas	44.56%	4.1	6.8	9.0
Hasselmus (Volumes from 3yr life extension)	44.56%	2.2	2.4	2.6
Gjøa P1	12%	4.2	6.2	7.4
Gjøa B1	12%	0.0	0.1	0.2
Grevling Stage 1	55%	9.8	16.3	25.3
Grevling Stage 2	55%	5.2	7.4	9.6
Yme life extension	15%	1.3	1.3	2.0
Total contingent volumes		**26.8**	**40.5**	**56.2**

4.1. GREVLING (PL038D)

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 is now being matured towards concept select / DG2 decision, based on a standalone development concept.

Figure 5: Grevling location map, North Sea

Discovery

The 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.

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.

Development

The Grevling field development has passed DG1 and is now undergoing a detailed concept select study towards DG2.

The base-case drainage strategy includes 4 horizontal producers and 2 horizontal water-alternating gas injectors. Artificial lift is required, but the final selection of technology depends on the development concept. The plateau oil rate is estimated to approximately 20,000 bbl/d.

Status

The Grevling project is moving towards a DG2 in Q2 2019, and planned s production start-up in 2021. However, the selection of development concept may shift the start-up date.

The volumes are based on the RNB 2019 submission, which are identical to the DG1 numbers.

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.

4.2. 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 total net OKEA volumes of the Hasselmus project ranges from 6.3 to 11.7 mmboe.

4.3. GJØA P1 RE-DEVELOPMENT AND B1 WELL

The Gjøa P1 project is soon to be sanctioned, with 4 wells in the northernmost segment of Gjøa. Oil and gas volumes of this development altogether 4.2 to 7.4 mmboe net to OKEA.

A change-out of the gas lift valve is planned for the B-1 well, increasing the net OKEA volumes by another 0.13 mmboe.

4.4. 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 1.33 – 2.04 mmboe.

5 Prospective resources

Prospective resources are defined as potentially recoverable from undiscovered accumulations. Table 7 shows the total overview of the prospective resources. One of the major prospects is located in the PL958 licence and in January an agreement was signed between A/S Norske Shell and OKEA AS to transfer the operatorship of this licence to OKEA. As a result, the prospective resources are reported as of 31 January 2019.

Table 7: Prospective Resources

Name of prospect	Interest	Net Unrisked Oil equivalents (million boe)			
		COS	Low	Base	High
Rialto	50%	0.12	45	151	289
Kathryn	16.67%	0.27	1	4	8
Hamlet	12%	0.72	2	2	3
Draugen Appraisal	44.56%	tbc	2	18	33
Total prospective volumes			**49**	**174**	**333**

5.1. PL958 RIALTO PROSPECT

The PL958 license to the east of Draugen, on the Trøndelag platform contains several prospects. The most promising at this early stage is the Rialto prospect, identified by a typical sand signature with significant lateral extent in the seismic. The play is the same as on Draugen, with reservoir in Late Jurassic Rogn Formation. Source is mainly the Spekk Formation, which charged Rialto via spill from Draugen. Charge is the main risk. The license has an “Acquire 3D seismic or drop” decision in June 2019.

5.2. PL910 KATHRYN

The Kathryn prospect a few kilometres East of the Yme Gamma structure. 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. The PL910 licensees have sanctioned an exploration well on Kathryn expected to be drilled Q2-Q3 2019.

5.3. PL153 HAMLET

The Hamlet prospect, within the Gjøa license, 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 is acquired in 2019 with drilling subject to rig availability, most likely 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.

5.4. DRAUGEN APPRAISAL

The Draugen Appraisal project is a low-cost appraisal campaign designed to assess in- and near-field prospects in the Draugen licence. The targets include the already defined Dansemus, Springmus, East Flank and Skumnisse prospects identified by Shell, as well as several newly established infill targets. The main differentiator from Shell’s work is the incorporation of the 2016 depth conversion, which improved the imaging of all prospects, as well as the 20-year production life ambition.

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 2018 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